EXHIBIT 5

DINE' CITIZENS AGAINST RUINING OUR ENVIRONMENT*
SAN JUAN CITIZENS ALLIANCE*
ENVIRONMENTAL DEFENSE*WESTERN RESOURCE ADVOCATES*
NATURAL RESOURCES DEFENSE COUNCIL*
SIERRA CLUB*FOREST GUARDIANS*
ENVIRONMENT COLORADO*CLEAN AIR TASK FORCE*
GRAND CANYON TRUST

November 13, 2006

By email *(desertrockairpermit@epa.gov* and *baker.robert@epa.gov) and Fed. Ex.*
Robert Baker (AIR-3)
Air Permitting
EPA Region IX
75 Hawthorne Street
San Francisco, CA 94105

RE: Comments on EPA's Proposed Construction Permit for Sithe Global Power to Construct the Desert Rock Energy Facility

Dear Mr. Baker:

Dine Citizens Against Ruining Our Environment, San Juan Citizens Alliance, Environmental Defense, Western Resource Advocates, Natural Resources Defense Council, Sierra Club, Forest Guardians, Environment Colorado, Clean Air Task Force, and Grand Canyon Trust (collectively referred to as "conservation organizations") respectfully submit the following comments on the EPA's proposed construction permit to be issued to Sithe Global Power (Sithe) to construct the Desert Rock Energy Facility (DREF) on Navajo Nation lands. Your point of contact for the conservation organizations will be Mark Pearson or Mike Eisenfeld at San Juan Citizens Alliance (970) 259-3583.

Included with this comment letter are the following five expert affidavits or reports that address certain deficiencies in the proposed DREF permit in greater detail:

1. Declaration of John Thompson, Clean Air Task Force, November 10, 2006.

2. "Comments on the Air Quality and Visibility Impact Analyses of the PSD Permit Application for the Desert Rock Energy Facility," prepared by Khanh Tran, AMI Environmental, October 5, 2006.

3. "Ozone Air Quality Analyses in the PSD Permit Application for the Desert Rock Energy Facility," prepared by Dr. Jana Milford, Environmental Defense, October 25, 2006.

4. "Review of the Class I SO2 PSD Increment Consumption Analyses Performed for the Desert Rock Prevention of Significant Deterioration Permit," prepared by Vicki Stamper, November 9, 2006.

5. "Cumulative SO_2 Modeling Analyses of Desert Rock Energy Facility and Other Sources at PSD Class I Areas," prepared by Khanh Tran of AMI Environmental, November 9, 2006.

Copies of the aforementioned affidavits and reports are attached hereto and are incorporated by reference in their entirety into this comment letter.[1]

As discussed in our comments provided below and in the attached reports, EPA's proposed issuance of this prevention of significant deterioration (PSD) permit is contrary to law on numerous grounds. Thus, EPA must not issue the permit for DREF as currently proposed and must instead provide adequate public notice and opportunity for public comment.

1. EPA FAILED TO MEET PUBLIC NOTICE REQUIREMENTS

Section 165(a)(2) requires that, in order for a PSD permit to be issued, "the proposed permit has been subject to a review in accordance with [section 165 of the Clean Air Act]. . .and a public hearing has been held with opportunity for interested persons. . .including representatives of the Administrator to appear and submit written or oral presentations on the air quality impact of such source, alternatives thereto, control technology requirements, and other appropriate considerations." In EPA's implementing regulations for PSD SIPs, it is stated that the public notice for a proposed permit must provide "the degree of increment consumption that is expected from the source." 40 C.F.R. §51.166(q)(2)(iii). The EPA's Environmental Appeals Board has interpreted these provisions as meaning that the public notice for a PSD permit must include the degree of increment consumption that is expected in all of the locations impacted by the proposed source. IN THE MATTER OF HADSON POWER 14-BUENA VISTA, PSD Appeal Nos. 92-3, 92-4, 92-5, 4 E.A.D. 258, 272-3 (EAB 1992). In particular the EAB noted "Different potential commentors may have an interest in different areas to be impacted and would want, and would reasonably be entitled to, available data on increment consumption at the area of their particular concern." *Id.* at 273.

EPA's public notice for the DREF as published in the Navajo Times on July 27, 2006 only listed one value for each pollutant for the "Modeled Class I Impacts." The notice did not make clear which Class I area the modeled impacts were modeled in, and it did not identify the predicted amount of increment consumption expected in all Class I areas to be impacted by DREF. Thus, the public did not know what Class I areas would be impacted by DREF, much less that at least six Class I areas in four states could be

[1] All documents cited or specifically relied upon in these comments are hereby incorporated by reference into the administrative record for the DREF PSD permit.

impacted by DREF.[2] Therefore, EPA failed to meet public notice requirements for the DREF proposed permit.

The imperative to provide public notice of increment consumption at specific class I areas flows directly from the core statutory purposes of the PSD program. Section 160(2) of the Clean Air Act plainly provides that a central statutory purpose of the PSD program is "to preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special national, scenic, or historic value." Congress also instructed that the PSD program is intended "to assure that any decision to permit increased air pollution in any area to which this section applies is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decisionmaking process." CAA Sec. 160(5). Adequate notice is a necessary predicate to informed public participation in the PSD permit process.

In addition to EPA's PSD public notice requirements, the federal public participation requirements at 40 C.F.R. §124.8 also require a discussion of the degree of increment consumption to be included in any fact sheet prepared by EPA for a PSD permit. See 40 C.F.R. §124.8(b)(3). It appears that EPA did prepare a fact sheet for the proposed DREF permit ("Desert Rock Energy Facility Proposed Clean Air Permit – Air Pollution Reduction Technology"), but this document did not provide the degree of increment consumption expected by the DREF in *any* area.

Thus, EPA failed to adequately inform the public of the degree of increment consumption expected by DREF in all areas to be impacted by the proposed facility and, accordingly, EPA must re-issue its public notice to comply with its public participation requirements.[3]

2. THE DRAFT AIR QUALITY PERMIT DOES NOT ADDRESS CARBON DIOXIDE AND OTHER GREENHOUSE GAS EMISSIONS

The proposed permit for the DREF does not address carbon dioxide (CO_2) or other greenhouse gases to be emitted from the proposed power plant. However, such emissions can be quite significant from coal-fire boilers. Due to its sheer size, the Desert Rock plant will be a significant contributor to global warming pollution in the West, with an estimated

[2] Sithe's modeling analysis of DREF indicated the facility would significantly impact SO2 increment at six Class I areas: Mesa Verde National Park, Weminuche Wilderness Area, San Pedro Parks Wilderness Area, Bandelier National Monument, Petrified Forest National Park, and Canyonlands National Park. January 2006 DREF Class I Area Modeling Update at 4-9.

[3] As discussed later in these comments, EPA also failed to develop an adequate analysis of impacts on soils and vegetation prior to issuing the draft permit and did not make a meaningful soils and vegetation analysis available prior to convening public hearings as required by the Act. EPA must also remedy this procedural flaw in the DREF permit.

13.7 million tons of carbon dioxide emitted to the air each year.[4] Its annual carbon dioxide emissions would be akin to the annual carbon dioxide emissions from 2.4 million cars.[5] As shown in the Table 1, the Desert Rock facility would increase heat-trapping carbon dioxide emissions from the existing coal-fired power plants in the West by over 5%, and it would rank among the top ten carbon dioxide emitters of all western coal-fired power plants.[6]

[4] Carbon dioxide emissions were calculated based on the maximum coal throughput of the two planned boilers of 382 tons per hour (as provided in the May 2004 Application for Prevention of Significant Deterioration Permit for the Desert Rock Energy Facility, at 2-9) and the U.S. EPA's AP-42 Emission Factors for subbituminous coal combustion at 1.1-42 (available at www.epa.gov/ttn/chief/ap42/index.html).
[5] Assumed an average annual carbon dioxide emission rate from cars of 11,450 pounds per year, as provided in the U.S. EPA's report "Average Annual Emissions and Fuel Consumption for Passenger Cars and Light Trucks," EPA-420-F-00-013 (April 2000).
[6] Based on comparison to the 2002-2003 average carbon dioxide emissions from existing Western coal-fired power plants obtained from the U.S. EPA's Clean Air Markets Database, available at http://www.epa.gov/airmarkets/emissions/prelimarp/index.html.

Table 1: Top Ten Western Coal-Fired Electric Utility Steam Generating Power Plants for CO_2 Emissions, Including the Proposed Desert Rock Power Plant[7]

Rank	Power Plant	Annual CO_2 Emissions, tons
1	Navajo	19,600,000
2	Colstrip	16,900,000
3	Jim Bridger	16,500,000
4	Four Corners	15,600,000
5	Intermountain	15,000,000
6	Laramie River	14,500,000
7	***Proposed Desert Rock Facility***	***13,700,000***
8	San Juan	13,400,000
9	Centralia	11,800,000
10	Craig	10,700,000

EPA is required to regulate CO_2 and other greenhouse gases as pollutants under the Clean Air Act. CO_2 and other greenhouse gases are squarely within the Act's definition of "air pollutant." The Act defines "air pollutant" expansively to include "any physical, chemical, biological, radioactive . . . substance or matter which is emitted into or otherwise enters the ambient air." § 302(g), 42 U.S.C. § 7602(g) (emphasis added). Further, the Act specifically includes carbon dioxide in a list of "air pollutants." Section 103(g) directs EPA to conduct a research program concerning "[i]mprovements in nonregulatory strategies and technologies for preventing or reducing multiple air pollutants, including . . . . . . carbon dioxide, from stationary sources, including fossil fuel power plants." 42 U.S.C. § 7403(g)(1)(emphasis added). EPA is required to regulate emissions of air pollutants, including CO_2, under a number of the Clean Air Act's major substantive provisions, when, in EPA's judgment, such emissions cause or contribute to air pollution which "may reasonably be anticipated to endanger public health or welfare." Egs. § 111 (establishing new source performance standards for categories of stationary sources); § 202 (establishing standards for emissions from new motor vehicles). Further, the Act's definition of "welfare," specifically includes effects on "climate" and "weather." § 302(h), 42 U.S.C. § 7602(h). Section 165(a)(2) plainly provides that a major emitting facility is "subject to the best available control technology for each pollutant subject to regulation under [the Clean Air Act] emitted from, or which results from, such facility."

As is discussed more fully below, coal-fired power plants are the nation's largest source of CO_2 emissions, and the scientific community is virtually unanimous in acknowledging the contributions of greenhouse gas emissions to climate change, i.e., global warming. EPA itself acknowledges numerous adverse effects to public health and welfare likely to result from global warming. See, e.g., **http://www.epa.gov/climatechange/**. EPA has no lawful basis for

[7] Based on a review of CO2 emissions from coal-fired electric utility power plants in the western states of Washington, Oregon, California, Idaho, Montana, Nevada, Wyoming, Utah, Colorado, Arizona and New Mexico. CO2 emissions for existing coal-fired electric utility power plants based on average of 2002-2003 CO2 emissions as reported to EPA's Clean Air Markets Database, available at http://www.epa.gov/airmarkets/emissions/prelimarp/index.html.

declining to limit carbon dioxide emissions from coal-fired power plants such as the proposed Desert Rock facility by reducing the extensive CO_2 emissions.

Twelve states, fourteen environmental groups and two cities have filed suit against EPA, asserting that EPA has ample authority under the Clean Air Act to regulate air pollutants associated with climate change and that EPA must adhere to the enumerated statutory factors in determining whether global warming pollution is reasonably anticipated to endanger public health and welfare. This issue is now before the U.S. Supreme Court, with oral argument scheduled for November 29, 2006.[8]

At minimum EPA/Sithe must consider the collateral environmental impacts of carbon dioxide emissions

The EPA has long recognized the obligation for a permitting authority to meaningfully consider collateral environmental impacts. *See In re North County*, 2 E.A.D. 229, 230 (Adm'r 1986). The Administrator stated in that case:

> Region IX's [asserts] that EPA lacks the authority to "consider" pollutants not regulated by the [CAA] when making a PSD determination. This assertion is correct only if it is read narrowly to mean EPA lacks the authority to impose limitations or other restrictions directly on the emission of unregulated pollutants. EPA clearly has no such authority over emissions of unregulated pollutants. Region IX's assertion is overly broad, however, if it is meant as a limitation on EPA's authority to evaluate, for example, the environmental impact of unregulated pollutants in the course of making a BACT determination for the regulated pollutants. EPA's authority in that respect is clear. . . . Hence, if application of a control system results directly in the release (or removal) of pollutants that are not currently regulated under the Act, the net environmental impact of such emissions is eligible for consideration in making the BACT determination. The analysis may take the form of comparing the incremental environmental impact of alternative emission control systems with the control system proposed as BACT; however, as in any BACT determination, the exact form of the analysis and the level of detail required will depend upon the facts of the individual case. Depending upon what weight is assigned to the environmental impact of a particular control system, the control system proposed as BACT may have to be modified or be rejected in favor of another system. In other words, *EPA may ultimately choose more stringent emission limitations for a regulated pollutant than it would otherwise have chosen if setting such limitations would have the incidental benefit of restricting a hazardous but, as yet, unregulated pollutant*.[9]

Consistent with this authority, the EAB has made it clear that EPA has an affirmative duty under the "environmental impact" prong of the BACT analysis, where competing BACT technologies would have different collateral environmental impacts, to specifically evaluated those impacts

[8] Commonwealth of Massachusetts, et al. v. EPA, U.S. Supreme Court Docket No. 05-1120 (cert. granted June 26, 2006). See Brief for the Petitioners, filed Aug. 31, 2006.

[9] The Board has consistently upheld his proposition. *See*, e.g., *In re Genesee Power Station*, 4 E.A.D. 832 (EAB 1993); *In re Steel Dynamics*, 9 E.A.D. 165 (EAB 2000).

and consider the relative benefits and disadvantages of competing options. This requirement grows directly from the language of CAA section 169(3).[10]

Accordingly, even were EPA to conclude (erroneously in our view) that CO_2 is not a regulated "pollutant" under the CAA or otherwise subject to BACT emission limitations, it still must assess any differences in the potential global warming impacts of competing BACT technologies as part of the mandatory collateral impacts analysis. By its very nature the collateral impacts analysis is intended to target pollutants that are otherwise unregulated under the PSD provisions – and nothing in the Act suggests that such analyses should be limited exclusively to "pollutants" that the CAA otherwise regulates.[11]

Significantly, none of the EPA's arguments (made in other contexts) about why the CAA should not directly regulate CO_2 as a "pollutant" are relevant to the consideration of CO_2's environmental impacts in the BACT analysis.[12] Considering CO2 in the BACT analysis carries none of the regulatory implications that EPA argues in other instances demonstrate that Congress did not intend to allow regulation of CO2 as a "pollutant" under the CAA. Rather, the consideration of CO_2 in the PSD context simply provides an additional informational tool to distinguish among competing technologies in order to identify the technology that is likely to have the smallest environmental footprint. That is, it is just another factor to be weighed in the balancing of benefits between competing technologies – albeit, an incredibly important consideration that should be accorded weight that is commensurate with the scope and magnitude of the potential environmental, ecological, and economic damage with which it is associated.

The scientific consensus around global warming, and the significance of anthropogenic sources, has reached a point of unanimity; that is to say, global warming is real, and people are contributing to this phenomenon in a significant way. Moreover, the likely impacts of global warming are profound. As a result, the sense of urgency related to addressing global warming – by reducing greenhouse gas emissions – has increased dramatically.[13]

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[10] In this context, it is clear that relevant differences may include differences in the quantity or nature of non-PSD air emissions, such as hazardous air pollutants, as well as impacts related to other factors such as water usage, solid waste handling, waste water or process water discharge, etc. *See, e.g.*, *In re General Motors*, 10 E.A.D. 360, 379-81 (discussing collateral impacts).

[11] EPA may also consider impacts from CO_2 emissions as a part of its analysis of alternatives under CAA § 165(a)(2); and indeed EPA must do so where, as here, commenters have directly raised the issue. However, EPA may not rely on its authority to consider CO_2-related impacts under section 165(a)(2) as an excuse to not property evaluate such impacts as a part of the BACT analysis.

[12] *See* 68 Fed. Reg. 52922. EPA's position that it may not regulate CO_2 under the CAA (under the Act's mobile source regulatory program in particular) is the subject of an ongoing law suit that is now before the U.S. Supreme Court. *Massachusetts vs. EPA*, 05-1120 (appealed from *Mass. v. EPA*, 415 F.3d 50 (D.C. Cir. 2005).

[13] Global emissions of carbon amount to more than seven billion tons each year, and in order to address the impending effects of serious climate destabilization we must take action now to reduce these emissions. The more carbon we add to the atmosphere, the more dramatic the rise in temperature will be, and the more severe the climate-related environmental impacts, social costs, human health effects, and impacts on habitat, species, ecosystems, and biodiversity. *See* SCIENTIFIC AMERICAN, What To Do About Coal (Sept. 2006) available at: http://www.sciam.com/article.cfm?chanID=sa006&articleID=0003F275-08F2-14E6-BFF883414B7F0000.

In the BACT context, there is also no reason to dismiss important considerations of CO_2 emissions simply because numerous sources collectively contribute to global warming. Indeed, many of the foundational regulatory provisions of the CAA, such as the National Ambient Air Quality Standard (NAAQS), are predicated on the principle of reducing relatively small quantities of emissions from large numbers of sources in order to reduce harmful levels of pollutants in the ambient air.[14] Indeed, the potential health, environmental, energy, and welfare consequences of global warming are profound, and reducing CO2 emissions (especially those associated with coal-fired power plants) is the single most important strategy to fight these effects.[15]

EPA itself recognizes that global warming is likely to have numerous and particularly severe adverse public health and environmental consequences, including direct heat-related effects, extreme weather events, climate-sensitive disease impacts, air quality effects, agricultural effects (and related impacts on nutrition), wildlife and habitat impacts, biodiversity impacts, impacts on marine life, economic effects, and social disruption (such as population displacement).[16] Indeed, numerous studies directly link global warming with increases in a variety of serious environmental, health, economic, and ecological impacts.[17]

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[14] CAA § 112 similarly seeks to bring levels of hazardous air pollutants down to safe levels by regulating multiple source and multiple source categories of certain pollutants. There are other examples as well (e.g., SO_2 reductions under the acid rain program, and the regulations of emission from mobile sources). As a former EPA Assistant General Counsel puts it, ignoring CO_2 in the collateral impacts analysis because of the collective contribution of numerous sources would be:

> a recipe for total inaction that has been rejected in considering other air pollution problems and should be as to CO_2 as well. Rather, sizable sources such as coal-fired power plants must be viewed in terms of their contribution to the cumulative problem of climate change and the need—at least in the absence of a comprehensive regulatory program of CO_2 control—to mitigate that contribution.

Foote, 34 ELR at 10665. See also Foote, 34 ELR 10663-665 (discussing among other things why consideration of CO_2 in this context would not have unintended negative environmental effects).

[15] *See, e.g*., SCIENTIFIC AMERICAN, What To Do About Coal (Sept. 2006), available at: http://www.sciam.com/article.cfm?chanID=sa006&articleID=0003F275-08F2-14E6-BFF883414B7F0000.

[16] *See* http://www.epa.gov/climatechange/effects/health.html.

[17] The Los Angeles Times recently reported on a new study that shows that global warming is likely to cause extreme events that will damage ecosystems, harm public health, and disrupt society well before the end of the century. *See* http://www.latimes.com/news/nationworld/nation/la-na-climate20oct20,0,4849957.story?coll=la-home-nation. *See, also* links to the following studies at http://www.pewclimate.org/global-warming-in-depth/environmental_impacts/reports/: Observed Impacts of Climate Change in the U.S., Coping With Global Climate Change: The Role of Adaptation in the United States, A Synthesis of Potential Climate Change Impacts on the United States, Coral Reefs & Global Climate Change: Potential Contributions of Climate Change to Stresses on Coral Reef Ecosystems, Forests & Global Climate Change: Potential Impacts on U.S. Forest Resources, Coastal and Marine Ecosystems and Global Climate Change: Potential Effects on U.S. Resources, Aquatic Ecosystems and Global Climate Change: Potential Impacts on Inland Freshwater and Coastal Wetland Ecosystems in the United States, Human Health & Global Climate Change: A Review of Potential Impacts in the United States, Ecosystems & Global Climate Change: A Review of Potential Impacts on U.S. Terrestrial Ecosystems and Biodiversity, Sea-Level Rise & Global Climate Change: A Review of Impacts to U.S. Coasts, Water and Global Climate Change: Potential Impacts on U.S. Water Resources, The Science of Climate Change: Global and U.S. Perspectives, Agriculture & Global Climate Change: A Review of Impacts to U.S. Agricultural Resources. STERN REVIEW ON THE ECONOMICS OF CLIMATE CHANGE, available at: http://www.hm-treasury.gov.uk/Independent_Reviews/stern_review_economics_climate_change/sternreview_index.cfm. These studies are incorporated here by reference.

EPA has never purported to carve out a CO_2 "exemption" under the PSD program, nor would such a carve-out be permissible under the statute. Moreover, because coal-fired power plants are the single largest source of CO_2 emissions, they are a critical part of any efforts to address the effects of global warming. In short, the consideration of the consequence of CO_2 emissions as a collateral environmental impact in the BACT analysis is completely independent of CO_2's status as a pollutant under the Act, and considering CO_2 emissions when a *new* coal plant is proposed (i.e. as a part of the process of pre-construction review), is *by far* the most cost-effective stage to evaluate the possibility of achieving reductions.[18]

Given the potential for extremely severe environmental and public health related impacts from global warming; given that the phenomenon of global warming is undeniably connected to anthropogenic releases of CO_2; given that electric power production is the single most significant source of CO_2 emissions in the U.S. and the world; and given that coal fired power plants (such as the one proposed by Sithe) contribute the vast majority of energy-sector CO_2 emission; it is simply untenable that the effects of global warming would be inherently outside the scope of the "collateral impacts" that permit applicants and permitting authorities must consider in connection with the issuance of PSD permits. Thus, any assertion that CO_2 emissions (and global warming) are somehow beyond the broad mandate to consider "environmental impacts" under the CAA generally and the PSD program in particular must be rejected.[19]

At a minimum, therefore, EPA must consider emissions of CO_2 in its BACT analysis for the DREF. The federal Environmental Appeals Board (EAB) has interpreted the definition of BACT as requiring consideration of unregulated pollutants in setting emission limits and other terms of a permit, since a BACT determination is to take into account environmental impacts.[20] A recently issued paper entitled *Considering Alternatives: The Case for Limiting CO_2 Emissions from New Power Plants through New Source Review* by Gregory B. Foote (attached hereto and listed as **Attachment 1** in the attached exhibit list) discusses the regulatory background to support consideration of CO_2 impacts when permitting a new source and, in particular, a new coal-fired power plant. This paper indicates that it is entirely appropriate to consider CO_2 emissions when evaluating environmental impacts under the new source review permit program, and the paper also suggested approaches for evaluating technologies in terms of CO_2 emissions. Further, support for consideration of greenhouse gas emissions in new source permitting can also be found in EPA's own New Source Review Workshop Manual (October 1990 draft) which states, "significant differences in noise levels, radiant heat, or dissipated static electrical energy, or greenhouse gas emissions may be considered" in permitting a new source or in the application

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[18] For example, industry would consider it cost prohibitive to consider retrofits for a pulverized coal plant in order to seriously address CO_2 emissions (by installing CO2 capture and control equipment for example).

[19] Such a position would necessarily read out of the Act the ability to address emerging environmental threats, and consider the real world consequence of specific industrial activities in the context where it matters most – the concrete permitting decisions that help to define the nature, scope, and impact of such activities. As discussed above, the Act itself clearly contemplates that permit applicants and permit issuers will evaluate, quite broadly, the environmental implications of individual projects. It follows, quite naturally, that carbon emissions and global warming would be among the concerns that are relevant in the process of permitting a coal-fired power plant, especially where competing BACT technologies would have significantly different life-cycle implications for global warming.

[20] See *In Re North County Resource Recovery Associates*, 2 E.A.D. 229, 230 (Adm'r 1986), 1986 EPA App. LEXIS 14.

of a specific technology. Attached hereto and listed as **Attachment 2** in the attached exhibit list hereto. Even the meager "Mitigation Proposal" negotiated between the Federal Land Managers and Sithe encompassed greenhouse gas emissions and impacts, plainly recognizing that these emissions affect air quality related values and impacts with the scope of the PSD program. Attached hereto and listed as **Attachment 64** in the attached exhibit list hereto ("Sithe Global Power, LLC (Sithe) Mitigation Proposal for the Desert Rock Energy Project (DREP), April 2006").

EPA/Sithe must consider the collateral costs of future CO2 regulation

BACT also requires consideration of costs that are relevant to the selections of one BACT option over another. In this context, costs associated with the future regulation of carbon dioxide emissions from power plants should be considered in deciding between BACT options for the DERF, and BACT options that are less intense emitters of CO2 should be given preference.

The regulation of CO2 emissions in the U.S. in the very near future is virtually certain. The international community has already begun to take action to curb such emissions – 190 countries have joined the United Nation's Framework Convention on Climate Change, and most have ratified the Kyoto Protocol (the U.S. and Australia alone among the industrialized countries have not). More recently certain States have also taken concrete steps to reduce their carbon footprint – for example, several Northeast States have formed the Region Greenhouse Gas Initiative (RGGI) to reduce carbon emission in that part of the country.[21] The state of California also has passed legislation to limit the state's greenhouse gas emissions, and to require that new long-term investments in baseload generation meet a minimum standard for greenhouse gas emissions, and several Western and Midwest States are now contemplating action to limit greenhouse gases. Moreover, members of Congress have introduced numerous bills, amendments, and resolutions specifically addressing global warming, and the Senate last year passed a resolution calling for a "comprehensive and effective national program of mandatory, market-based limits and incentives on emissions of greenhouse gases that slow, stop, and reverse the growth of such emissions."[22,23] Studies continue to show that such regulation is the only responsible and economically sensible course of action; for example the Stern Report[24] concluded that while the cost of inaction could range from 5-20% of global GDP, the cost of stabilizing ambient concentrations at 450 to 550 ppm CO_2-equivalent can be accomplished for about 1% of GDP. According to the report, the key policies required to meet this goal are the implementation of carbon emission regulations (such as cap and trade measures), the deployment of low carbon-technologies and further low-carbon innovation, and the removal of barriers to energy efficiency.

[21] See www.rggi.org.
[22] Senate Amendment 866 a Sense of the Senate climate change resolution proposed by Senators Bingaman, Specter, Domenici, Alexander, Cantwell, Lieberman, Lautenberg, McCain, Jeffords, Kerry, Snowe, Collins and Boxer adopted by a vote of 53 to 44 on June 22, 2005. Congressional Record, Vol. 151, June 22 2005, S7033 – S7037, S7089.
[23] See www.aip.org/fyi/2005/114.html. In May of this year the House Appropriations Committee approved similar language. See www.pewclimate.org/what_s_being_done/in_the_congress/index.cfm for more information on Congressional action on global warming.
[24] STERN REVIEW ON THE ECONOMICS OF CLIMATE CHANGE, available at: http://www.hm-treasury.gov.uk/Independent_Reviews/stern_review_economics_climate_change/sternreview_index.cfm..

The general consensus in the U.S. is that federal CO_2 emission controls are inevitable. Notably, the utility industry as well has begun to recognize that national carbon emission limits are both necessary and desirable – for example, executives from Duke Energy and NRG have recently made statements strongly supporting the idea of national carbon limits, and emphasizing the responsibility of the electric power sector to take action to address global warming.[25] Because power generation is the single most significant source of CO_2 in the United States (accounting for nearly 40% of U.S. emission), this industry – and coal-fired power generation in particular – is certain to be among the first industry sectors affected by carbon-related regulation.

As the momentum to regulate greenhouse gas emissions continues to grow around the country and internationally, businesses are increasingly recognizing the monetary risk associated with impending carbon emissions controls. For example:

- PacifiCorp and Idaho Power Company have explicitly addressed the financial risk associated with carbon emissions in their recent IRPs. Idaho Power's draft IRP, for example, explains that the utility analyzed the financial risk of carbon emissions because "it is likely that carbon dioxide emissions will be regulated within the thirty year timeframe addressed in the 2004 IRP."[26]
- PG&E's long-term plan recognizes the risk of increasing costs for carbon emissions.
- Last year, the Coalition for Environmentally Responsible Economies (CERES) convened a Dialogue among experts from the power sector, environmental groups, and the investment community focusing on climate change. The Dialogue participants found that greenhouse gas emissions will be regulated in the U.S., and that the "issue is not whether the U.S. government will regulate these emissions, but when and how."[27]
- Utility shareholders are recognizing that the likelihood of regulation of carbon emissions represents a real financial risk, and are asking utilities to disclose those risks. Thirteen major public pension funds, which manage $800 billion in assets, recently asked the Securities and Exchange Commission to require companies to disclose the financial risks they face from climate change.[28] Meanwhile, in 2004 alone institutional shareholder groups filed 29 proposals asking individual companies to outline their response to global warming.

There is overwhelming evidence that carbon emissions will likely be regulated in the very near future, and accordingly, businesses in the U.S. are taking this financial risk quite seriously.[29]

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[25] *See, e.g.*, http://www.cleartheair.org/proactive/newsroom/release.vtml?id=25835.
[26] See PacifiCorp, "2003 Integrated Resource Plan," www.pacificorp.com Idaho Power Company, "Draft 2004 Integrated Resource Plan," www.idahopower.com/energycenter/2004irpdraft.htm.
[27] Coalition for Environmentally Responsible Economies, "Electric Power, Investors, and Climate Change," June 2003, p. 4 (www.ceres.org/reports/main.htm).
[28] Margaret Kriz, "Measuring The Climate For Change," Congress Daily, April 22 2004.
[29] Moreover, emission allowances that effectively "grandfather" the CO2 emissions of existing power plants (particularly those plants being permitted now – when the writing is already on the wall) is highly unlikely and would be entirely inappropriate. Rather, it is probable that the Congress will adopt legislation in the near term that is consistent with the 2005 U.S. Senate resolution calling for a "comprehensive and effective national program of

In short, the costs associated with the imminent regulation of CO2 (certainly within the lifetime of the proposed DREF) should be expressly considered in connection with the selection of BACT. Because the DREF proposes to use a carbon-intensive pulverized coal technology, and because other BACT options have significantly better CO2 emissions performance (in particular IGCC, as discussed below – especially when used in conjunction with carbon capture and disposal),[30] the cost of future CO2 regulation is directly relevant to the BACT analysis in this case. To the extent that EPA fails to fully evaluated this cost consideration it will be in violation of its statutory obligations under the CAA.[31]

3. THE DRAFT AIR QUALITY PERMIT DID NOT ADEQUATELY EVALUATE INTEGRATED GASIFICATION COMBINED CYCLE AS AN AVAILABLE METHOD TO LOWER AIR EMISSIONS IN THE BACT ANALYSIS

EPA's Ambient Air Quality Impact Report (NSR 4-1-3, AZP-04-01) (hereinafter "AAQIR") explains that the EPA did not require evaluation of IGCC as BACT for the DREF because consideration of IGCC would be redefining the source. AAQIR at 35.

The EPA's determination that IGCC would be redefining the source is wrong. The Clean Air Act's definition of BACT specifically requires consideration of inherently lower emitting processes.

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mandatory, market-based limits and incentives on emissions of greenhouse gases that slow, stop, and reverse the growth of such emissions." Given the number of plants being proposed and the fact that the Senate is on record calling for a program to reduce emissions, the law is likely to limit emission allowances to coal plants that were fully permitted or actually in operation prior to the Senate resolution (at the latest). This would be particularly appropriate in a state such as New Mexico, where the Governor has already adopted specific, numeric greenhouse gas reduction targets by executive order. The Desert Rock facility, for example, would pose a direct threat to the state's ability to meet its goals for reducing greenhouse gas emissions.

[30] IGCC inherently emits less CO2 than pulverized coal technologies, but it also provides the ability to capture and dispose of CO2 in order to reduce CO2 emission by perhaps 80-90%.

[31] There are various cost estimates related to future carbon dioxide emissions control that span a range from about $8 per ton to $40 per ton. For example, there is currently a carbon dioxide trading program in Europe that serves as one component of European efforts to address global warming. In that trading program, carbon dioxide emissions have reached a high of about $42 per ton. *See* http://pubs.acs.org/subscribe/journals/esthag-w/2006/jul/business/mb_carbonprices.html. Several states in the U.S. have specifically required consideration of future carbon costs as a part of their energy planning processes. In particular, the California Public Utilities Commission requires that the utilities use a "greenhouse gas adder" of $8 per ton CO_2, beginning in 2004 and escalated at 5% per year, in long-term planning and procurement for purposes of evaluating new long-term resource investments. See California Public Utilities Commission, Decision No. 04-12-048, and Decision 05-04-024. The Montana Public Service Commission has a similar requirement. See Montana Public Service Commission, "Written Comments Identifying Concerns Regarding Northwestern Energy's Compliance with A.R.M. 38.5.8201-8229," Docket No. N2004.1.15, *In the Matter of the Submission of Northwestern Energy's Default Electricity Supply Resource Procurement Plan* (August 17, 2004). Idaho Power is using a carbon cost of $14/ton starting in 2012. See http://www.idahopower.com/energycenter/irp/2006/2006IRPFinal.htm As a result, reasonable estimates for CO_2 costs under expected U.S. regulations range from about $8 to about $40 per ton. Even assuming a relatively low carbon cost, of say $12 per ton, it is clear that emission from a facility like DREF could create a significant financial burden.

Integrated Gasification Combined Cycle (IGCC) is an available, demonstrated coal combustion technology with significant emission reduction benefits. There are numerous benefits to IGCC, including fewer emissions of criteria and hazardous air pollutants, the opportunity for capturing greenhouse gases, such as CO_2, that cause global warming, and a general increase in efficiency over other coal burning technologies.

Federal Law Requires a Thorough Evaluation of IGCC as Part of the BACT Analysis.

Section 165(a)(4) of the Clean Air Act (CAA) provides that "no major emitting facility on which construction is commenced after August 7, 1977, may be constructed in any area to which this part applies unless…the facility is subject to the best available control technology for each pollutant subject to regulation under this chapter emitted from, or which results from, such facility."[32] The requirement for conducting a BACT analysis is codified in the Federal PSD regulations at 40 C.F.R. § 52.21(j). 40 C.F.R. § 52.21(n) further requires that "the owner or operator of a proposed source. . . shall submit. . .all information necessary to perform any analysis or make any determination" required under the PSD regulations."

BACT requires a comprehensive analysis of all potentially available emission control measures, expressly including input changes (such as use of clean fuels), process and operational changes, and the use of add-on control technology. Additionally, it requires that a new source comply with emission limits that correspond to the *most effective* control measures available, unless the source can affirmatively demonstrate that use of the most effective control measures would be technologically or economically infeasible.

BACT is specifically defined under Federal law as follows:

> an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each pollutant subject to regulation under the [Clean Air] Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.[33]

EPA has repeatedly acknowledged that the PSD program is technology forcing and intended to become more stringent over time as control technologies improve and new cleaner processes are introduced. For example, the EAB has explained that:

> A major goal of the CAA was to create a program that was technology forcing. . . . "The Clean Air Amendments were enacted to 'speed up, expand, and intensify the war against air pollution in the United States with a view to assuring that the air we breathe throughout the Nation is wholesome once again.'" . . . .

[32] 42 U.S.C. §7475(a)(4).
[33] 40 C.F.R. §52.21(b)(12), emphasis added. See also CAA§169(3), 42 U.S.C. §7479(3).

> In keeping with this objective, the program Congress established was particularly aggressive in its pursuit of state-of-the-art technology at newly constructed sources. At these sources, pollution control methods could be efficiently and cost-effectively engineered into plants at the time of construction.[34]

Similarly, the EPA Administrator has explained that the BACT provisions of the PSD program are principally technology-forcing and are intended to foster "rapid adoption" of improvements in emissions control technology.[35]

The definition of BACT includes coal gasification. The legislative history of the amendment adding the term "innovative fuel combustion techniques" to the Clean Air Act's definition of "BACT" is clear. Coal gasification must be considered. The relevant passage of the debate is excerpted below:

> Mr. HUDDLESTON. Mr. President, the proposed provisions for application of best available control technology to all new major emission sources, although having the admirable intent of achieving consistently clean air through the required use of best controls, if not properly interpreted may deter the use of some of the most effective pollution controls. The definition in the committee bill of best available control technology indicates a consideration for various control strategies by including the phrase "through application of production processes and available methods systems, and techniques, including fuel cleaning or treatment." And I believe it is likely that the concept of BACT is intended to include such technologies as low Btu gasification and fluidized bed combustion. But, this intention is not explicitly spelled out, and I am concerned that without clarification, the possibility of misinterpretation would remain. It is the purpose of this amendment to leave no doubt that in determining best available control technology, all actions taken by the fuel user are to be taken into account--be they the purchasing or production of fuels which may have been cleaned or up-graded through chemical treatment, gasification, or liquefaction; use of combustion systems such as fluidized bed combustion which specifically reduce emissions and/or the post-combustion treatment of emissions with cleanup equipment like stack scrubbers. The purpose, as I say, is just to be more explicit, to make sure there is no chance of misinterpretation. Mr. President, I believe again that this amendment has been checked by the managers of the bill and that they are inclined to support it.
>
> Mr. MUSKIE. Mr. President, I have also discussed this amendment with the distinguished Senator from Kentucky. I think it has been worked out in a form I

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[34] *In Re Tenn. Valley Authority*, 9 E.A.D. 357, 391 (EAB 2000) (citing *WEPCO*, 893 F.2d at 909 and H.R. Rep. No. 95-294, at 185, *reprinted in* 1977 U.S.C.C.A.N. at 1264).

[35] *In re Columbia Gulf Transmission* Co., 2 E.A.D. 824, 828-29 (Adm'r 1989). *See also In re Kawaihae Cogeneration Project*, 7 E.A.D. 107, 127 n.26 (EAB 1997); *In re Metcalf Energy Center*, PSD Appeal 01-7, 01-8, at 15 (Aug. 10, 2001).

can accept. I am happy to do so. I am willing to yield back the remainder of my time.[36]

Clearly, both the language of the Act itself and the unequivocal expressions of Congressional intent in the legislative history indicate, that in order to fully comply with the Act, the emission limits identified as BACT must incorporate consideration of more than just add-on emission control technology – they must also reflect appropriate considerations of fuel quality (such as low sulfur coal) and process changes (including specifically innovative combustion techniques such as coal gasification). Indeed, this requirement is not only consistent with, but necessary to the very core objective of PSD permitting – to bring about the rapid adoption of cleaner technologies that provide for a greater reduction in regulated emissions.[37] In "notably capacious terms," *Alaska v. EPA,* 540 U.S. 461 (2004), the statute provides that BACT includes "application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques." CAA Sec. 169(3).

EPA and federal courts have consistently interpreted the BACT provisions found in the CAA and the agency's regulations as embodying certain core criteria that require the permit applicant either to implement the most effective available means for minimizing air pollution or justify its selection of less effective means on grounds consistent with the purposes of the Act. Indeed, the discretion of the permitting agency in determining BACT is deliberately confined by the statute's use of the "strong, normative terms 'maximum' and 'achievable.'" *Alaska v. EPA,* 540 U.S. 461 (2004).

In *Citizens for Clean Air v. EPA*,[38] the Ninth Circuit held that "initially the burden rests with the PSD applicant to identify the best available control." As stated in long-standing EPA guidance, "[r]egardless of the specific methodology used for determining BACT, be it 'top-down,' 'bottom-up,' or otherwise, the same core criteria apply to any BACT analysis: the applicant must consider all available alternatives, and [either select the most stringent of them or] demonstrate why the most stringent should not be adopted."[39] Accordingly, the PSD permit applicant not only must identify all available technologies, including the most stringent, but it must also provide adequate justification for dismissing any available technologies.

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[36] 95th Congress, 1st Session (Part 1 of 2) June 10, 1977 Clean Air Act Amendments of 1977 A&P 123 Cong. Record S9421.

[37] Emission controls under the CAA are universally recognized as including process changes (including inherently cleaner processes) as well as add-on control technology. The PSD provisions expressly recognize this in the definition of BACT included in section 169 of the Act. Other sections of the Act reinforce the fact that Congress generally understood and accepted that emission control is often most effectively achieved through process changes. *See* CAA § 112(d)(2) (identifying mechanisms for reducing emission of hazardous air pollutants as including, in addition to add-on controls, "process changes, substitutions of materials or other modifications," as well as "design, equipment, work practice, or operational standards").

[38] 959 F.2d 839, 845 (9th Cir. 1992)

[39] Memorandum from John Calcagni, Director of EPA Air Quality Management Division, to EPA Regional Air Directors (June 13, 1989), at 4 (emphasis added).

Consistent with these core criteria, the EPA's New Source Review (NSR) Workshop Manual establishes that, as the first step in the "top-down" BACT analysis, the applicant *must* consider all "available" control options:

> The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of <u>production process or</u> <u>available methods, systems, and techniques</u>, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. This includes technologies employed outside of the United States. As discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.[40]

"The term 'available' is used…to refer to whether the technology 'can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term.'"[41] In keeping with the stringent nature of the BACT requirement, EPA has repeatedly emphasized that "available"

> is used in the broadest sense under the first step and refers to control options with a "practical *potential* for application to the emissions unit" under evaluation. . . . The goal of this step is to develop a comprehensive list of control options.[42]

EPA adjudicatory decisions also examine the core requirements for the BACT determination process. "Under the top-down methodology, applicants must apply the best available control technology unless they can demonstrate that the technology is technically or economically infeasible. The top-down approach places the burden of proof on the *applicant* to justify why the proposed source is unable to apply the best technology available."[43]

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[40] NSR Manual, at p. B.5 (emphasis added).

[41] <u>In re: Maui Electric Company</u>, PSD Appeal No. 98-2 (EAB September 10, 1998), at 29-30 (quoting NSR Manual at B.17).

[42] <u>In re: Knauf Fiber Glass</u>, PSD Appeal Nos. 98-3 – 98-20 (EAB February 4, 1999), at 12-13 (quoting NSR Manual at B.5) (emphasis added by EAB); <u>see also</u> <u>In re: Steel Dynamics, Inc.</u>, PSD Appeal Nos. 99-4 and 99-5 (EAB June 22, 2000), at 29 n.24 (citing <u>Knauf</u> with approval); NSR Manual at B.10 ("The objective in step 1 is to identify all control options with potential application to the source and pollutant under evaluation."); <u>id.</u> at B.6 (emphasizing that a proper Step 1 list is "comprehensive").

[43] <u>In re: Spokane Regional Waste-to-Energy Applicant</u>, PSD Appeal No. 88-12 (EPA June 9, 1989), at 9) (internal quotation marks omitted) (emphasis in original); <u>see also</u> <u>In re: Inter-Power of New York, Inc.</u> PSD Appeal Nos. 92-8 and 92-9 (EAB March 16, 1994) ("Under the 'top-down' approach, permit applicants must apply the most stringent control alternative, unless the applicant can demonstrate that the alternative is not technically or economically achievable."); <u>In the Matter of Pennsauken County, New Jersey Resource Recovery Facility</u>, PSD Appeal No. 88-8 (EAB November 10, 1988) ("Thus, the 'top-down' approach shifts the burden of proof to the applicant to justify why the proposed source is unable to apply the best technology available.")

Whatever analytical process is utilized for determining BACT, these core criteria – the requirement to consider all available technologies, including the most stringent, and to provide adequate justification in the administrative record for dismissing any of the technologies based on relevant statutory factors – must be satisfied.[44]

Thus, to conduct a BACT analysis consistent with the requirements of Federal law for the DREF, EPA must thoroughly evaluate all available control measures. IGCC is commercially available today. Federal law therefore requires that this technology be thoroughly evaluated as part of the DREF BACT analysis.

<u>EPA's Erred in Failing to Consider IGCC in the BACT Analysis for Desert Rock Because It Would be "Redefining the Source"</u>

In the "Ambient Air Quality Impact Report" (AAQIR) which reflects EPA Region 9's analysis and justification for its permitting decision in this case, EPA explains that it has not even assessed the possibility of achieving additional emission reductions from the proposed Desert Rock facility through process changes. That is, EPA has utterly ignored in the context of its evaluation of Sithe's PSD permit, process options for generating electricity from coal that could significantly reduce emissions from the facility.[45] This decision on the part of EPA Region 9 flies in the face of the plain language of the Act, the clear expressions of Congressional intent, and the rulings of the Environmental Appeals Board.

Instead of evaluating, or requiring the permit applicant to seriously evaluate, potential process changes (like IGCC) that could significantly reduce the proposed facility's emissions, EPA states:

> Consideration of Integrated Gasification Combined Cycle (IGCC) technology . . . has not been included in step 1 of the BACT analysis above, since IGCC would be redefining the source.

AAQIR at 35.[46] This categorical dismissal of any obligation on the part of the permit issuer to consider or evaluate the availability, applicability, effectiveness, collateral environmental benefits, or cost effectiveness of a recognized process option for further reducing emission from coal-fired power plant is flatly contrary to the Agency's responsibilities under the PSD program.

EPA has argued in other contexts that the concept of "redefining the source" may relieve it of certain obligations under the PSD program.[47] In particular, in the *Prairie State* case before the EAB, EPA argued as a matter of statutory interpretation that the CAA did not contemplate that permitting authorities would require a permit applicant to consider building a source other than the one it had proposed. In that case, the issue involved whether a proposed Illinois coal-fired power plant, that was being planned in conjunction with a new coal mine, needed to consider (as a element of its BACT analysis) using coal that was lower in sulfur than the coal that the co-

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[44] The EAB has made clear that, regardless of the analytic process, if a control option is left out of the analysis because it is erroneously identified as not potentially available, the permit will be sent back on appeal. *See In re Three Mountain Power*, 10 E.A.D. 39, 50 (EAB 2001) (explaining that "proper BACT analysis requires consideration of all potentially 'available' control technologies").

located mine would produce. EPA argued (as did Illinois EPA) that requiring the source to use coal other than that from the co-located mine would constitute an impermissible redefinition of the source.

Ultimately, in a very narrow ruling, the Board in the *Prairie State* case held that the use of coal from the co-located mine was so integral to the very purpose and intent of the project that requiring the permit applicant to consider using some other source of coal instead would defeat the purpose of the original permit application. Accordingly, the Board ruled that the Illinois EPA did not "clearly err when it determined that consideration of low-sulfur coal, because it necessarily involves a fuel source other than the co-located mine, would require Prairie State to redefine the fundamental purpose or basic design of its proposed Facility, and that, therefore, low-sulfur coal could appropriately be rejected from further BACT analysis at step 1 of the top-down review method." Prairie State at 36-37.

Even assuming that the Board's decision in Prairie State was consistent with the CAA, that decision clearly demonstrates that EPA's failure to require consideration of innovative combustion technologies as process options for controlling emission from the Desert Rock plant is fundamentally flawed. First, the EAB's ruling recognized that the default assumption under the CAA's PSD provisions is that the use of potentially cleaner fuels (such as low-sulfur coal) will normally be a required part of the BACT analysis.[48] Only where some unique element of the facility's basic purpose made the particular BACT-related consideration *fundamentally incompatible* with the permit application, did the EAB recognize that further analysis of that BACT-related consideration might by unnecessary.[49]

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[45] In particular, the use of Integrated Gasification Combined Cycle (IGCC) would allow the facility to produce electricity from coal with dramatically lower emission of NOx, SOx, CO, VOC, and PM. *See, e.g.,* Permit Application for Nueces IGCC Plant (submitted to Texas Commission on Environmental Quality September 2006).

[46] Although EPA claims to have requested "detailed information from Sithe regarding whether or not IGCC would be technically feasible," that "detailed information" consists of approximately ten pages of discussion, much of which is simply inaccurate. Moreover, as Region 9 did not scrutinize this analysis, draw any conclusions from it, or discuss it *at all* as a component of its decision-making, it failed to meet its statutory obligation as the permitting authority in this case, and has denied the public any opportunity to understand or respond to the nature or scope of its reliance on the Sithe analysis. Accordingly, even were EPA to rely on the Sithe analysis to conclude that IGCC is not technically or economically feasible in this instance, it must first specifically evaluate the Sithe analysis and specifically justify any reliance on that analysis, and thereafter allow the public an opportunity to evaluate and comment on EPA's conclusions.

[47] *See In re Prairie State Generating Co*., PSD Appeal 05-05, 13 E.A.D. __ (Sept. 24, 2006).

[48] Prairie State at 22 ("Petitioners correctly observe that . . . consideration of 'clean fuels' must be a part of the BACT analysis. Specifically, . . . the Agency must consider both the cleanliness of the fuel and the use of add-on pollution control devices."). Indeed, numerous other PSD permits have identified the use of clean fuel (including low sulfur coal) as BACT for new major sources. *See, e.g. In re AES Puerto Rico* 8 E.A.D. 324 (EAB 1999); *In re Encogen Cogeneration*, 8 E.A.D. 244 (EAB 1999); *In re Hawaiian Commercial & Sugar Co.y*, PSD Appeal No. 92-1 at 5, n.7 (EAB, July 20, 1992).

[49] In *Prairie State* the Board concluded that the mine and the coal-fired power plant were proposed together as a single source under the PSD provisions, and the mine was intended to supply the entirety of the power plant's fuel throughout the plant's entire operating life. Therefore, the EAB concluded, the plant and the mine were integral parts of a single proposal and the use of coal from another source would undermine the purpose of that proposal. If the mine were capable of supplying less than the full fuel needs of the power plant over its entire life cycle, for example, the Board's analysis would likely have been different; the Board's decision suggests that in such a case the consideration of low-sulfur supplemental fuel would have been required.

In the end, even the Board's decision in Prairie State reflects an understanding that the concept of redefining the source must be subordinate to the primary objectives of the BACT analysis. That is, the specific requirements inherent in the definition of BACT will define the obligations of permit applicants and permitting authorities, unless some specific fundamental conflict exists. Moreover, while the Board concluded that the permit issuer should look "in the first instance" at "how the permit applicant, in proposing the facility, defines the goals, objectives, purposes, or basic design for the proposed facility," the permit applicant cannot manipulate the definition of the facility as a mechanism to avoid appropriate BACT analysis. *Prairies State* at 29-30. In evaluating the permit, the permit issuer must "discern which design elements are inherent to [the] purpose [of the facility], articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility." *Id.* at 30.

Significantly, the Board specifically recognized that cost savings are not a valid purpose for a particular facility design; similarly, "the business objective of avoiding risk associated with new, innovative or transferable control technologies is not treated as a basic design element." *Prairies State* at 30 n.23. Rather cost and risk considerations are appropriately addressed during the later steps of the top-down BACT analysis.

For Desert Rock, EPA seeks to stretch the EAB's recognition of a narrow exception to the BACT requirements *far* beyond the breaking point, by flatly rejecting the idea that a PSD permit applicant *ever* needs to evaluate the achievability of emission reductions from process changes or innovated combustion techniques for converting coal into electricity. As described above, EPA states simply that requiring an applicant to examine the possibility of using an inherently less polluting process (such as IGCC, or presumably CFB, or other advanced coal-to-energy technology) is categorically beyond the scope of what the Act requires because it would redefine the source.

This position is out of sync with both the Act itself and with the EAB's treatment of the concept of "redefining the source." First, as discussed above, the Act specifically calls for consideration of "the application of *production processes* and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or *innovative fuel combustion techniques* for control of each pollutant." CAA § 169(3). This language, on its face, requires as a part of the BACT analysis the consideration of innovative technologies like IGCC that make the generation power from coal significantly cleaner.[50]

Further, the two early decisions by the EPA Administrator that introduce the "redefining the source" policy, identify a policy that is much more limited that that which EPA now advocates. In *In re Pennsauken County, New Jersey, Resource Recovery Facility* the petitioner asked the EPA Administrator to deny a PSD permit to a municipal waste combustor and, instead, require the county to dispose of its waste by co-firing it with coal in existing power plants. *See* PSD Appeal No. 88-8 at 10 (Adm'r, Nov. 10, 1988). In effect, the petitioner wanted the EPA to order the applicant to engage in a different type of activity: electricity generation, rather than waste disposal. The Administrator rejected this option because the petitioner's argument was based on

[50] As discussed above, the legislative history of the CAA is equally as clear that the definition of BACT contemplates consideration of technologies like IGCC.

his objection to a waste combustor generally, not to the conditions in the permit. Thus, the Administrator held, the petitioner was asking EPA to "redefine the source" from a waste combustor to a power plant.[51] The Administrator subsequently reaffirmed the *Pennsauken County* decision and explained that "source," within the newly created "redefining the source" policy, refers to a *source category*.[52]

After clarifying the "redefining the source" policy as only preventing a change in the "fundamental purpose," i.e., the source category, the Administrator further explained that the "redefining the source" policy did not allow the permitting agency to blindly accept the source design proposed by the applicant. *Id.* at 842-843. In *Hibbing*, the permit applicant wanted to burn petroleum coke at its taconite plant, but EPA required the applicant to consider burning natural gas – a lower polluting process and cleaner fuel – as part of a BACT determination. *Id.* The Administrator specifically rejected the idea that requiring consideration of cleaner fuel constitutes "redefining the source" because the fundamental purpose, or source category, remains the same.[53]

In other words, *from its inception*, prior to the 1990 Manual, the "redefining the source" policy has merely stood for the concept that EPA will not require an applicant to abandon its intended purpose for some other industrial venture. To the extent EPA's subsequently-issued *draft* NSR Manual is inconsistent with prior Administrator interpretations in *Pennsauken* and *Hibbing*, which constitute the agency's official position, the draft Manual is not entitled to any deference.[54]

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[51] "Petitioner Filipczak's fundamental objections to the Pennsauken permit are not with the control technology, but rather, with the municipal waste combustor itself. He urges rejection of the combustor in favor of co-firing a mixture of 20% refuse derived fuel and 80% coal at existing power plants. These objections are beyond the scope of this proceeding and therefore are not reviewable under 40 C.F.R. 124.19, which restricts review to "conditions" in the permit. Permit conditions are imposed for the purpose of ensuring that the proposed source of pollutant emissions-- here, a municipal waste combustor-- uses emission control systems that represent BACT, thereby reducing the emissions to the maximum degree possible. These control systems, as stated in the definition of BACT, may require application of "production processes and available methods, systems, and techniques, including fuel cleaning as treatment or innovative fuel combustion techniques" to control the emissions. The permit conditions that define these systems are imposed on the source as the applicant has defined it… [T]he source itself is not a condition of the permit." *Pennsauken County* at 10-11 (emphasis added).

[52] "In Pennsauken, the petitioner was urging EPA to reject the proposed source (a municipal waste combustor) in favor of using existing power plants to co-fire a mixture of 20% refuse derived fuel and 80% coal. In other words, *the petitioner was seeking to substitute power plants (having as a fundamental purpose the generation of electricity) for a municipal waste combustor (having as a fundamental purpose the disposal of municipal waste)." In re Hibbing Taconite Company*, 2 E.A.D. at n. 12 (Adm'r 1989) (parentheticals original, emphasis added).

[53] [O]ne argument that could be made is that the Region, by requiring the burning of natural gas to be an alternative to be considered in the BACT analysis [for a petroleum coke-fired plant], is seeking to "redefine the source." Traditionally, EPA has not required a PSD applicant to redefine the *fundamental scope* of its project… [The redefining the source] argument has no merit in this case.
EPA regulations define major stationary sources by their product or purpose (e.g., "steel mill," "municipal incinerator," "taconite ore processing plant," etc.), not by fuel choice. Here, *Hibbing will continue to manufacture the same product (i.e., taconite pellets) regardless of whether it burns natural gas or petroleum coke…* The record here indicates that there are other taconite plants that burn natural gas, or a combination of natural gas and other fuels. Thus, it is reasonable for Hibbing to consider natural gas as an alternative in its BACT analysis. *Id.* (parentheticals original, emphasis added).

[54] In addition to simply being wrong, the NSR Manual's application of the "redefining the source" policy is due no deference because it conflicts with the agency's prior interpretations. *See Pauley v. Beth-Energy Mines*, 501 U.S.

Because the Act specifically calls for consideration of *production processes* and *innovative fuel combustion techniques* as means for reducing emissions from industrial sources regulated under the PSD program, even the Board's analysis in *Prairie State* would require evaluation of IGCC as part of the BACT analysis, *unless there were a specific, objectively discernable reason why doing so would be fundamentally at odds with the primary objective of the project, based on appropriate considerations not related to cost or the avoidance of risk*.[55] For Desert Rock, EPA has articulated no such rationale.[56] What EPA suggests by way of its off-hand dismissal of IGCC is that consideration of such control measures is never appropriate under the Act.[57] As discussed above, this position is simply untenable as a matter of statutory interpretation. Moreover, it also runs counter to the EAB's favorable consideration of Illinois EPA's requirement for permit applicants to consider IGCC.

In *Prairie State*, the Petitioners argued that the scope of EPA's "redefining the source" policy lacked any "principled standards," and would therefore allow permit applicants to define-away basic elements of the BACT analysis. *See Prairie State* at 33. The EAB rejected this argument, but in doing so relied specifically on Illinois EPA's policy of requiring consideration of IGCC to demonstrate why the policy was not fatally overbroad.[58] *Id* 33-37. The Board noted that Illinois EPA "required Prairie State to submit a detailed analysis of [IGCC] as a method for controlling emissions from the proposed Facility." *Prairie State* at 35.[59] The Board explained, "IGCC is not simply an add-on emission control technology, but instead would have required a completely redesigned 'power block.' . . . [Illinois EPA's] demand that Prairie State provide a detailed analysis of IGCC, which [Illinois EPA] noted has the promise to achieve greater [emissions] reductions, demonstrates that [Illinois EPA's] application of the policy against redefining the design of the source through application of BACT did not treat "very few" design changes as consistent with the proposed Facility's basic design. . . . To the contrary, [Illinois EPA's] consideration of IGCC demonstrates that [it] gave due regard to Prairie State's objective in submitting a permit application for the proposed Facility, namely development of an electric

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680, 698 (1991) (no deference to agency interpretations that are inconsistent with previously held view); *see also Malcomb v. Island Creek Coal Co*., 15 F.3d 364, 369 (4th Cir. 1994) (deference is not due to an agency interpretation of its own rules that is inconsistent); Brotherhood of *Locomotive Engineers v. Atchison, Topeka Santa Fe R.R. Co*., 116 S.Ct. 595, 133 L.Ed.2d 535 (1996).

[55] "The assertion, and finding, that the design is for reasons independent of air quality permitting must be reasonable and supported by the record." *Prairie State* at 34 n.29. For Desert Rock, however, EPA has failed to even make an evidence-based finding that IGCC is incompatible with the purpose of the project – it merely asserts, without record-based explanation, that consideration of IGCC would constitute redefining the source. This is both substantively inadequate and inadequate as a matter of public notice.

[56] In addition to rendering this part of the BACT analysis inadequate, EPA's failure to specifically identify why IGCC would be fundamentally incompatible with the objectives of this project has deprived commenters of EPA's essential rationale for a major part of its decision. Accordingly, EPA must describe the basis for its determination and provide the public with an opportunity to comment on its rationale.

[57] EPA said as much in a December 13, 2005 letter to an energy consulting company. That letter is now the subject of a settlement agreement under which EPA acknowledges that the letter has no legal significance or legally binding effects on anyone.

[58] If the EAB affirmed IEPA's authority to require consideration of IGCC, such consideration must be within the permitting authority's discretion under the statutory definition of BACT, and therefore cannot be a fundamental "redefinition" of the source that is impermissible under the Act.

[59] The Board references a letter from Donald Sutton, Illinois EPA to Diana Tickner, Prairie State (March 29, 2003), that letter is incorporated by reference here.

power generating plant that would be co-located and co-permitted with a 30-year supply of fuel, and then explored every potential add-on technology and potentially lower-emitting production processes or methods consistent with that basic design to determine the maximum emissions reductions achievable for the Facility." *Id* at 35-36.[60]

In contrast, for the Desert Rock facility (which like the Prairie State facility is an electric power generating plant that would be co-located with a proprietary coal supply), EPA has completely abrogated its BACT-related responsibilities when it comes to identifying "every potential add-on technology *and potentially lower-emitting production processes or methods* consistent with that basic design to determine the maximum emissions reductions achievable." Instead, EPA has casually referenced the policy against "redefining the source" as a justification to completely ignore the plain language of the statute and the clear expressions of Congressional intent.

While the Board ultimately concluded in *Prairie State* that IGCC was not required at the facility, that determination resulted from the Board's conclusion that IGCC was essentially equivalent to the proposed boiler technology in terms of its potential emission control effectiveness. *See Prairie State* at 47. That conclusion was the unfortunate result of a poor record. As discussed at length below, it is very clear that IGCC is capable of achieving a level of emissions performance for virtually every regulated PSD pollutant that is significantly better than the performance of a pulverized coal boiler.[61] Moreover, IGCC plants have a multitude of collateral environmental benefits: they achieve better reductions in hazardous air pollutants like mercury, they produce less solid waste, they use less water, and they both emit less CO_2 and provide the ability to capture CO_2 emissions for permanent storage to help address global warming. Accordingly, the

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[60] In its analysis, the Board specifically recognized that EPA guidance requires consideration of process-related technology advances like IGCC. *Prairie State* at 33 ("The NSR Manual also states with respect to production processes, that where 'a given production process or emission unit can be made to be inherently less polluting' 'the ability of design considerations to make the process inherently less polluting *must be considered* as a control alternative for the source.'"). The Board went on to explain that "viewing the proposed facility's basic design as something that generally should not be redefined through BACT review does not prevent the permit issuer from taking a 'hard look' at whether the proposed facility may be improved to reduce its pollutant emissions." *Id* at 33-34. By "hard look" it is clear that the Board means a real, substantive BACT examination that explains in detail the technological, engineering, process, and/or design factors that make a particular emission control option incompatible with the projects objectives. *See Prairies State* at 34 (citing *Knauf*, 8 E.A.D. 121, 127 (EAB 1999)). The Board explained that a permit issuer's failure to take a sufficiently hard look at the design issues has "the potential to circumvent the purpose of BACT, which is to promote use of the best control technologies as widely as possible." *Prairie State* at 34 (quoting *Knauf*, 8 E.A.D. at 140). Significantly, the EAB gave short shrift to EPA's essentially meaningless "alternatives analysis" which would have relegated consideration of any process, technique or alternative approach to pollution control to an analysis separate and apart from the BACT determination. EPA's treatment of IGCC in the Desert Rock case is a perfect illustration of the danger that the EAB identified as inherent in the concept of a "redefining the source" exemption – EPA has not taken a "hard look" at whether IGCC might be an appropriate consideration under the BACT analysis here, and EPA's casual dismissal of its obligations in this regard threaten to "circumvent the purpose of BACT."

[61] The PSD permit application for Nueces Syngas, LLC for example, includes emission limits for the IGCC turbines (in lb/MMBTU) of 0.018 for NOx, 0.017 for SO_2, 0.037 for CO, 0.003 for VOC, 0.006 for PM and PM_{10}, and 0.001 for H_2SO_4. There are other recent permit applications in the record that also demonstrate the tremendous opportunities for emission reductions with IGCC. Moreover, this technology is now a viable and ready option for electric power production, as evidenced by among other things the 25 or so proposed IGCC plants around the country. See the Department of Energy's document: Tracking New Coal-Fired Power Plants, available at: http://www.netl.doe.gov/coal/refshelf/ncp.pdf.

Board's justification for rejecting IGCC in the Prairie State case is simply inapplicable for the Desert Rock plant.[62]

Indeed, EPA itself has publicly recognized IGCC as an "inherently low-polluting process/practice,"[63] and has reaffirmed its view that IGCC is an available method for cleaning and treating coal to remove air pollutants prior to combustion:

> One approach to controlling SO_2 emissions from steam generating units is to limit the maximum sulfur content in the fuel. This can be accomplished by burning… a fuel that has been pre-treated to remove sulfur from the fuel… There are two ways to pre-treat coal before combustion to lower sulfur emissions: Physical coal cleaning and gasification… Coal gasification breaks coal apart into its chemical constituents (typically a mixture of carbon monoxide, hydrogen, and other gaseous compounds) prior to combustion. The product gas is then cleaned of contaminants prior to combustion. Gasification reduces SO_2 emissions by over 99 percent.[64]

As a result of fuel cleaning, IGCC units "will inherently have only trace SO_2 emissions because over 99 percent of the sulfur associated with the coal is removed by the coal gasification process." 70 Fed. Reg. at 9715.[65]

Documents obtained through FOIA further demonstrate that EPA seriously erred in its treatment of IGCC in this permit proceeding. Attached hereto and listed as **Attachment 62** in the attached exhibit list hereto. In detailed notes of an EPA meeting with the permit applicant, Sithe officials explain that Sithe has extensive experience with IGCC: "Sithe did the 1st IGCC in the world." (Statement of Dick Straussfeld). At the same time, Sithe officials steadfastly refuse to submit an IGCC analysis as part of the BACT determination and EPA agrees. In detailed notes reflecting a pivotal exchange between Sithe and EPA officials, it is manifest that EPA has pre-ordained the outcome of the permit proceeding in contravention of basic procedural rights and protections, that EPA agreed with the permit applicant up front before any opportunity for notice

[62] Moreover, to the extent that Sithe or EPA is concerned about cost implications of IGCC, the technological availability or reliability of the technology, or other technological or economic considerations, the appropriate mechanism to address those concerns is the BACT top-down analysis – not through up-front exclusion of the technology from consideration.

[63] *See, e.g.*, Robert J. Wayland, U.S. EPA Office of Air and Radiation, OAQPS, "U.S. EPA's Clean Air Gasification Activities", Presentation to the Gasification Technologies Council Winter Meeting, January 26, 2006, slide 4; and "U.S. EPA's Clean Air Gasification Initiative", Presentation at the Platts IGCC Symposium, June 2, 2005, slide 11 (citing the "inherently lower emissions of nitrogen oxides, sulfur dioxides, and mercury," as among the "fundamental advantages" of IGCC). Mr. Wayland also correctly notes that IGCC units use less water, and produce fewer global warming pollutants than conventional pulverized coal units, another point relevant to the statutory directive to "take into account environmental . . . impacts" in determining BACT limits. Wayland January 26, 2005 Presentation, Slide 4; 42 U.S.C. § 7479(3).

[64] U.S. EPA, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, 70 Fed. Reg. 9706, 9710-11 (February 28, 2005).

[65] Indeed, IGCC is a prime example of "fuel cleaning" (which also is a required BACT consideration under the Act) – involving the *pre-combustion* transformation of otherwise dirty coal into a fuel (syngas) that can be more cleanly burned in a combined-cycle power block.

and public comment that IGCC would not be considered as part of the BACT analysis and that the meager information submitted by Sithe on IGCC was designed merely to paper the record not to aid EPA in engaging in reasoned decision-making on the merits. Here is the pivotal exchange reflects an EPA decision-making process that is contrary to the core procedural and substantive requirements of a PSD permit determination:

> "Bob said project as proposed probably satisfies BACT for a P.C. Boiler, even sets a new standard. Need a complete record that looks at all technologies. Coal gasification (IGCC) info was submitted but was confusing, we need additional info. Circulating fluidized bed (CFB) – also more info including costs. Ann asked that it be framed in a top-down analysis. Gus said he doesn't think IGCC should be BACT and will not go on record as submitting it as BACT. Bob said OK. Said top-down doesn't work for IGCC since it's a process technology, not dedicated to a pollutant. Ann stated that there are 2 EAB decisions that opened the door – we need to deal with it. Gus said in the next 2-3 weeks will get us a report on IGCCV and CFB."

See listing as **Attachment 62** to the exhibit list attached hereto (FOIA Appeal**,** FOIA Request #09-RIN-00434-06, Sept. 19, 2006 Correspondence from Enrique Manzanilla, EPA, Director, Communities and Ecosystems Division, to Environmental Defense ("Desert Rock meeting with applicant,"under heading "BACT issues")**.**

Because the CAA and implementing regulations clearly require evaluation of technologies like IGCC which can achieve the statutory intent of reducing emissions through process changes, available methods and systems and techniques, innovative combustion techniques, and fuel cleaning, and because EPA failed entirely to conduct an analysis of IGCC as a possible control option, the draft PSD permit is unlawful and the public has unlawfully been deprived of the opportunity to meaningfully engage with the agency on this issue. Therefore, the draft permit must be withdrawn, EPA must evaluate in detail the potential for applying IGCC, and the Agency must make its determination and its justification available for public comment.[66]

<u>Recent State Actions Requiring Consideration of Cleaner Coal Technology Establish Irrefutable Precedence for the Consideration of IGCC.</u>

In recent PSD permitting actions implementing the Federal PSD permitting program (either through a direct delegation from EPA or via approval of equivalent state rules in a state

[66] Even were EPA correct that it may ignore IGCC in the context of BACT based on the policy against "redefining the source" (which it cannot), there is no argument whatsoever that EPA does not retain discretionary authority under both the BACT provisions and under the "alternatives" provision of section 165(a)(2) to require consideration of IGCC (on this point the EAB precedent is crystal clear). The arguments presented here regarding appropriateness of considering IGCC as BACT apply equally to the need for EPA to consider IGCC as an alternative under 165(a)(2). Thus, to the extent that EPA does not exercise its authority under section 165(a)(2), even in light of significant and detailed public comments indicating that IGCC should be considered and adopted for Desert Rock, EPA must offer a rational explanation for its decision adequate to demonstrate that its refusal is not an abuse of discretion. It is clear, however, as discussed above, that the consideration of IGCC in connection with the BACT analysis is both appropriate and required in this instance, and EPA should not use is discretion under the "alternatives" language in section 165(a)(2) as a justification to avoid its statutory obligation under section 165 and 169(3) to require consideration of IGCC in the BACT analysis – one is not an adequate replacement for the other.

implementation plan (SIP)), several states have required consideration of IGCC in the BACT review process for new coal-fired power plants. These state decisions implementing the federal PSD program validate the plain language of the definition of BACT described above.

Specifically, in March 2003, the State of Illinois required the applicant for a proposed CFB coal-fired electric generation facility to conduct a robust analysis of IGCC as a core element of its BACT analysis:

> Additional material must be provided in the BACT demonstration to address Integrated Gasification Coal Combustion (IGCC) as it is a `production process' that can be used to produce electricity from coal. In this regard, the Illinois EPA has determined that IGCC qualifies as an alternative emission control technique that must be addressed in the BACT demonstration for the proposed plant. In addition, based on the various demonstration projects that have been completed for IGCC, the Illinois EPA believes that IGCC constitutes a technically feasible production process.
>
> Accordingly, Indeck must provide detailed information addressing the emission performance levels of IGCC, in terms of expected emissions rates and possible emission reductions, and the economic, environmental and/or energy impacts that would accompany application of IGCC to the proposed plant. This information must be accompanied by copies of relevant documents that are the basis of or otherwise substantiate the facts, statements and representations about IGCC provided by Indeck. In this regard, Indeck as the permit applicant is generally under an obligation to undertake a significant effort to provide data and analysis in its application to support the determination of BACT for the proposed plant.[67]

In an ensuing letter, the State of Illinois then formally informed EPA that Illinois has "concluded that it is appropriate for applicants for [proposed coal-fired power plants] to consider IGCC as part of their BACT demonstrations."[68]

Similarly, the Georgia Department of Natural Resources, in a March 2002 letter regarding the permit application of Longleaf Energy Station, also relied, in part, on the failure of the permit applicant to consider cleaner coal combustion technology in finding the application deficient. In making its determination of deficiency, Georgia stated that the applicant did not "discuss any other methods from generating electricity from the combustion of coal, such as pressurized fluidized bed combustion or integrated gasification combined cycle."[69] Georgia further stated that the applicant "should discuss these technologies and explain why you elected to propose a pulverized coal-fired steam electric power plant instead."[70]

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[67] Letter from Illinois Division of Air Pollution Control to Jim Schneider, Indeck-Elwood, LLC (March 8, 2003), Attachment 3 .
[68] Letter from Illinois EPA Director to EPA Regional Administrator, Region V (March 19, 2003), Attachment 4.
[69] Letter from James A. Capp, Manager, Stationary Source Permitting Program, Georgia DNR, to D. Blake Wheatley, Assistant Vice President, Longleaf Energy Associates, LLC (March 6, 2002). Attachment 5.
[70] *Id.*

Reflecting the viability of IGCC, the State of New Mexico issued a letter on December 23, 2002 requiring the permit applicant for a new coal-fired power plant to conduct a site-specific analysis of IGCC as well as CFB as part of the BACT analysis for the proposed facility: "The Department requires a site-specific analysis of IGCC and CFB in order to make a determination regarding BACT for the proposed facility." The New Mexico determination goes on to provide: "The analysis must include a discussion of the technical feasibility and availability of IGCC and CFB for the proposed site in McKinley County, including a discussion of existing IGCC and CFB systems."[71]

On August 29, 2003, New Mexico issued its evaluation of the applicant's response. New Mexico found that the applicant's BACT analysis had in fact indicated that IGCC is commercially available but that the applicant had improperly relied on cost to find that the technology was infeasible:

> Mustang concludes that neither IGCC nor CFB are technically feasible control options for the Mustang site. After careful review of the revised BACT analysis, as well as information gathered from independent sources, the Department determines that Mustang's conclusion is not supported by the evidence. Accordingly, the Department finds that Mustang has not demonstrated the technical infeasibility of IGCC and CFB. Moreover, applying the criteria in the NSR Manual, the Department determines that IGCC and CFB are technically feasible at the Mustang site, and must be evaluated in the remaining steps of the top down BACT methodology.
>
> (a) IGCC and CFB are technically feasible at the Mustang site. A technology is considered to be technically feasible if it is commercially available and applicable to the source under consideration. *See* NSR Manual at B.17-18. A technology is commercially available if it has reached a licensing and commercial sales stage of development. *Id.* A technology is applicable if it has been specified in a permit for the same or a similar source type. *Id.* Mustang's revised BACT analysis indicates that IGCC is commercially available, and IGCC has been specified in air quality permits for coal-fired power plants. *See, e.g.,* Lima Energy Facility, 580 megawatt coal-fired power plant. Similarly, CFB is commercially available and has been specified in air quality permits for coal-fired power plants. *See, e.g.,* AES Puerto Rico 454 megawatt coal-fired power plant; Reliant Energy Seward 584 megawatt coal-fired power plant.
>
> (b) For both IGCC and CFB, Mustang improperly relies on cost to determine technical infeasibility. A technology is technically feasible when the resolution of technical difficulties is a matter of cost. *See* NSR Manual at B.19-20. Mustang's revised BACT analysis indicates that the resolution of technical difficulties for both IGCC and CFB are a matter of cost. These costs do not support a finding of technical infeasibility, but may be considered

71 Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Corporation (Dec. 23, 2002). Attachment 6.

during Step 4 of the top down BACT methodology. *See* NSR Manual at B.26.[72]

In addition, the Montana Board of Environmental Review found that the Montana Department of Environmental Quality must consider IGCC as an available technology in the BACT review for a coal-fired power plant. Specifically, the Board of Environmental Review stated ". . .the Department should require applicants to consider innovative fuel combustion techniques in their BACT analysis and the Department should evaluate such techniques in its BACT determination in accordance with the top-down five-step method."[73]

It is important to note that, while some of these states were operating under SIP-approved PSD programs, the definition of BACT that applied in all cases is virtually identical to the federal definition of BACT with respect to consideration of inherently lower emitting processes. It is noteworthy that these states determined it was entirely appropriate to require consideration of IGCC in the BACT review for a coal-fired power plant.

The aforementioned state determinations are attached hereto.

<u>EPA Region 8 Has Also Determined It Was Appropriate to Evaluate IGCC in the BACT Analysis for a Coal-Fired Power Plant</u>

Further, EPA Region 8 submitted comments to the Utah Division of Air Quality in an April 6, 2004 letter on Utah's proposed permit for NEVCO Energy's Sevier Power Company Project in which EPA requested that further documentation on costs be provided to support Utah's claim that IGCC was too costly.[74] EPA did not indicate that IGCC didn't need to be considered as an alternative for the proposed Sevier CFB boiler. Instead, EPA stated "It is our understanding that IGCC is a potentially lower polluting process than Circulating Fluidized Bed combustion." EPA's comments requesting more documentation of the costs of IGCC provide strong indication that EPA found it appropriate to consider IGCC in the BACT analysis.

Thus, for all of the reasons described above, EPA erred in failing to fully evaluate IGCC for DREF in a top-down BACT review. Below we have provided an analysis of IGCC in a top-down BACT review and the results indicated that IGCC is the top technology.

<u>Information about IGCC is Readily Available and EPA is Obligated to Meaningfully Examine Such Information for Desert Rock's Permit</u>

Gasification is not a new technology, but rather one that has been around for at least a hundred years. Detailed information about the gasification process and IGCC is readily available to the utility industry and regulatory decision-makers, including EPA. For example, the Gasification

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[72] Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Company (Aug. 29, 2003), at p. 3, Attachment 7.
[73] Montana Board of Environmental Review, Findings of Fact, Conclusions of Law, and Order In the Matter of the Air Quality Permit for the Roundup Power Project (Permit No, 3182-00), Case No. 2003-04 AQ (June 23, 2003) at 18-19. See Attachment 9 for a copy of this finding.
[74] April 6, 2004 letter from Richard R. Long, EPA, to Rick Sprott, Utah Division of Air Quality, at 1 (Attachment 8).

Technologies Council (GTC) (which "was created in 1995 to promote a better understanding of the role Gasification can play in providing the power, chemical and refining industries with economically competitive technology options to produce electricity, fuels and chemicals in an environmentally superior manner") maintains a website with copious information about gasification, IGCC, specific IGCC technologies, vendor products, and existing IGCC projects. *See* http://www.gasification.org/.[75]

Among other things, the GTC accurately explains that "Gasification offers the cleanest, most efficient method available to produce synthesis gas from low or negative-value carbon-based feedstocks such as coal, petroleum coke, high sulfur fuel oil or materials that would otherwise be disposed as waste. The gas can be used in place of natural gas to generate electricity, or as a basic raw material to produce chemicals and liquid fuels." Among the important information available on the GTC website are papers and presentations compiled into an on-line library that can function as an important resource for both utilities and regulators. *See* http://www.gasification.org/library.htm. Among the important resources on this website is information about gasification generally, IGCC, and use of IGCC with low-rank coals;[76] information about the readiness of IGCC technology and the appropriateness of requiring examination of IGCC as a part of the BACT analysis;[77] information about polygeneration and capture of global warming gases from gasification plants;[78] and information about IGCC projects currently in the works.[79] Indeed, the GTC's 2006 annual conference this summer generated literally dozens of papers and presentations about gasification and IGCC technology.[80]

In the face of the remarkable wealth of available information, EPA has made the clearly arbitrary decision to ignore IGCC entirely as a possible option for the proposed Desert Rock facility. Even a cursory examination would demonstrate that IGCC is a technology that has arrived and that is available *now* as an option for utilities planning new coal-based power plant projects,[81] and that information regarding the technology is readily available to appropriately inform the top-down BACT decisionmaking process.[82] Moreover, it is clear that EPA is aware that IGCC is

[75] The Department of Energy also has a website dedicated to gasification: http://www.netl.doe.gov/technologies/coalpower/gasification/database/database.html.

[76] http://www.gasification.org/Docs/Bismarck%2006/02Amick.pdf; http://www.gasification.org/Docs/Bismarck%2006/01Phillips.pdf.

[77] http://www.gasification.org/Docs/Tampa%2006/Ely.pdf.

[78] http://www.gasification.org/Docs/Bismarck%2006/03RJones.pdf; http://www.gasification.org/Docs/Bismarck%2006/05pan.pdf.

[79] http://www.gasification.org/Docs/Bismarck%2006/07Smet.pdf;

[80] http://www.gasification.org/Presentations/2006.htm Additional technical information about IGCC and carbon capture and storage is available from U.S government websites, environmental organizations, and organizations like the World Energy Council (see http://www.worldenergy.org/wec-geis/focus/ccs/; http://www.fe.doe.gov/sequestration/index.html; http://www.pewclimate.org/). The fifth annual conference on carbon capture and sequestration was held this past May just outside Washington, D.C. (see http://www.carbonsq.com/).

[81] Even the utility industry is beginning to acknowledge the all-too-obvious fact that the time for IGCC has come and that the nation must begin to seriously address its carbon future. See: http://www.cleanenergypartnership.org/news/article_detail.cfm?id=231. Sadly, when it come to carbon emissions, global warming, and advance coal technologies, even the utility industry, it appears, is out in front of EPA.

[82] In addition to the tremendous amount of activity directed at refining the technology, making it cheaper, more reliable, and more commercially attractive, the fact that there are now more than 25 proposals for IGCC plants

a technology that is rapidly becoming a market force in the utility industry – for example, in July 2006 EPA issued a report entitled Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies,[83] which examined various aspects of IGCC.[84] Given the wealth of available information, the fact that EPA has failed utterly to examine the possibility of employing IGCC as a technology option for the proposed Desert Rock plant is especially egregious and demonstrably at odds with its statutory responsibilities.[85]

EPA should conduct a full top-down analysis for this project, including (among other things) examination of: [86]

- The technological availability of IGCC;
- The dramatic reduction in pollutant emissions that IGCC is capable of achieving;
- The various collateral environmental benefits of IGCC, including reductions of non-PSD air pollutants, reductions in generation of solid waste, decreased water use, and potential for capture and storage of global warming gases;
- The potential for reduced impacts on soil, vegetation, endangered or threatened species and habitat; and
- The economic and energy benefits of IGCC fuel and product flexibility.

EPA has an independent and affirmative obligation to evaluate IGCC as a possible technology option, and to specifically scrutinize any rationale offered by Sithe relating to IGCC. [87]

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nationwide make it clear that it is an option that is technologically available. See http://www.netl.doe.gov/coal/refshelf/ncp.pdf.

[83] *See* http://www.gasification.org/Docs/News/2006/EPA%20-%20IGCC%20cf%20PC.pdf.

[84] This report however, by its own terms, was a snapshot in time of the state of IGCC, based on 2004 information – information that is now badly out of date (especially given the rapid advances being made in this dynamic field). Even from a PSD perspective, a two-year-old analysis is inadequate (PSD permits expire after eighteen months precisely because the information upon which they are predicated is expected to become stale as processes and control technologies become more effective at reducing pollutant emissions). In this case, the data upon which EPA relied for its IGCC Footprints report simply cannot alone function as the basis for a case-specific analysis of IGCC for the proposed Desert Rock facility.

[85] Other information that EPA should consider in its examination of IGCC for Desert Rock includes among other things:
http://www.ciel.org/Publications/CO2_Foote_11May04.pdf (article by Greg Foote, former EPA Assistant General Council); http://www.synapse-energy.com/Downloads/SynapsePaper.2006-06.Climate-Change-and-Power.pdf (report by Synapse Energy Economics); http://www.grida.no/climate/ipcc_tar/wg2/index.htm(Climate Change 2001 Report); http://www.synapse-energy.com/Downloads/SynapseReport.2006-02.SCE.Mohave-Alternative-Generation-Resources.05-020.pdf (Synapse Mojave Report); http://www.epa.gov/climatechange/ (information available on EPA's own climate web site); http://www.publicaffairs.noaa.gov/pdf/economic-statistics-may2006.pdf (NOAA economic statistics); http://www.wvecouncil.org/issues/gambling_with_coal.pdf (Union of Concerned Scientists Report); STERN REVIEW ON THE ECONOMICS OF CLIMATE CHANGE, available at: http://www.hm-treasury.gov.uk/Independent_Reviews/stern_review_economics_climate_change/sternreview_index.cfm.

[86] Given the wealth of information regarding IGCC, EPA is not subject to a reduced burden of regulatory consideration for IGCC. *See In re Mecklenburg*, 3 E.A.D. 492, 494 n.3 (Adm'r 1990).

[87] Sithe's discussion of IGCC in its "Design Comparison" document is woefully inadequate and in many ways disingenuous. For example, the document is intentionally misleading about the level of emissions performance achievable using IGCC (IGCC is capable of performing *much* better then Sithe suggests, as evidenced by the best emission limits included in permit applications for IGCC plants); it also incorrectly suggests that altitude would stand as a technological barrier to the use of IGCC (at most issues related to altitude would raise cost considerations

Moreover, the public is entitled to examine and comment on EPA's analysis and conclusions – to the extent that the public has been denied that opportunity by EPA's failure to independently examine IGCC (or to specifically scrutinize Sithe's analysis and conclusion) EPA's permit decision is procedurally flawed and must the withdrawn and corrected, and the public must be given an opportunity to meaningfully participate through additional notice and comment proceedings.[88]

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that would need to be examined at step four of the BACT analysis – but without a full BACT analysis this issue has not been adequately explored).

[88] The following materials are incorporated by reference and are attached to this letter as **Attachment 9**: (1) LETTER TO STEPHEN L. JOHNSON, ADMINISTRATOR, US ENVIRONMENTAL PROTECTION AGENCY RE: December 13, 2005 Memorandum "Best Available Control Technology Requirements for Proposed Coal-Fired Power Plant Projects," signed by Stephen D. Page, Director, EPA Office of Air Quality Planning and Standards. (2) APPENDICES TO LETTER TO STEPHEN L. JOHNSON, ADMINISTRATOR, US ENVIRONMENTAL PROTECTION AGENCY RE: December 13, 2005 Memorandum "Best Available Control Technology Requirements for Proposed Coal-Fired Power Plant Projects," signed by Stephen D. Page, Director, EPA Office of Air Quality Planning and Standards.
(a) **APPENDIX 1**. Letter from Mr. Stephen D. Page, Director, US EPA Office of Air Quality Planning and Standards (OAQPS), to Mr. Paul Plath, Senior Partner, E3 Consulting, LLC, "Best Available Control Technology Requirements for Proposed Coal-Fired Power Plant Projects," (December 13, 2005). Also available at http://www.epa.gov/Region7/programs/artd/air/nsrmemos/igccbact.pdf (last visited February 6, 2006). (b) **APPENDIX 2**. Letter from Mr. Paul Plath, Senior Partner, E3 Consulting, LLC, to Mr. Steve Page and Mr. Dan Deroeck, U.S. EPA, "Analysis of Best Available Control Technology for a Non-Specific Coal-Fired Power Project" (February 28, 2005). (c) **APPENDIX 3**. "EPA's Position on IGCC," electronic mail from Richard Long, Director, U.S. EPA Region 8 Air and Radiation Program to Don Vidrine, Bureau Chief, Air Resources Management Bureau, Montana Department of Environmental Quality, and to other state permitting authorities in Region 8 states (December 13, 2005)(covering and forwarding an email from Scott Mathias, Associate Director, Information Transfer and Program Integration Division, U.S. EPA Office of Air Quality Planning and Standards, also dated December 13, 2005, and attaching the Page memo, the February 2005 E3 Plath request letter, and an EPA document entitled "igcc bact q&a.doc"). (d) **APPENDIX 4**. Gregory B. Foote, Considering Alternatives: The Case For Limiting CO2 Emissions From New Power Plants Through New Source Review, 34 ELR 10642 (July 2004). (e) **APPENDIX 5**. Jay Ratafia-Brown, et al., Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report ES-5 (DOE/NETL Contract Number DE-AT26-99FT20101 (December 2002). (f) **APPENDIX 6**. The ERORA Group, L.L.C., Prevention of Significant Deterioration, Title V Operating Permit & Phase II Acid Rain Joint Application for Cash Creek Generating Station, Henderson County KY, Volume 1 of 2, (July 2005). (g) **APPENDIX 7**. Wisconsin Department of Natural Resources Permit No. 03-RV-166, Elm Road Generating Station North Site With Accommodations (January 14, 2004). (h) **APPENDIX 8**. Edward Lowe, General Manager, Gasification, GE Energy, GE's Gasification Developments, presented at Gasification Technologies 2005 Conference, San Francisco, CA, (October 10, 2005). (i) **APPENDIX 9**. Ron Herbanek, Mechanical Engineering Director, E-Gas and Thomas A. Lynch, Project Development Manager, ConocoPhillips, E-Gas Applications for sub-Bituminous Coal, presented at Gasification Technologies 2005 Conference, San Francisco, CA, (October, 11 2005). (j) **APPENDIX 10**. George Boras and Neville Holt, EPRI, Pulverized Coal and IGCC Plant Cost and Performance Estimates, presented at the Gasification Technologies 2004 Conference Washington DC (October 3-6, 2004). (k) **APPENDIX 11**. The ERORA Group, Taylorville Energy Center IGCC Feasibility Analysis, report prepared pursuant to agreement no. SIUC 04-15 with Southern Illinois University (January 2005). (l) **APPENDIX 12**. Robert J. Wayland, U.S. EPA Office of Air and Radiation, OAQPS, "U.S. EPA's Clean Air Gasification Activities", Presentation to the Gasification Technologies Council Winter Meeting, January 26, 2006. (m) **APPENDIX 13**. Robert J. Wayland, U.S. EPA Office of Air and Radiation, OAQPS, "U.S. EPA's Clean Air Gasification Initiative", Presentation at the Platts IGCC Symposium, June 2, 2005. (n) **APPENDIX 14**. Letter from Renee Cipriano, Director, Illinois Environmental Protection Agency, to Mr. Thomas Skinner, Regional Administrator, U.S. EPA Region V, Re: Scope of Evaluation of Best Available Control Technology (BACT) Integrated Gasification Coal Combustion (IGCC) (March 19, 2003). (o) **APPENDIX 15**. Letter from Donald E. Sutton, Manager, Permit Section, Division of Air Pollution Control, Illinois Environmental Protection Agency, to Jim Schneider, Indeck-Elwood LLC, "Request for Additional Information" Re: Application No. 02030060 (March

Below we have provided an analysis of IGCC in a top-down BACT review and the results indicated that IGCC is the top technology.

IGCC Analysis for the DREF

Step 1: Identify All Available Control Technologies.

Conclusion: IGCC is an Available Control Technology

Coal gasification projects have gained wide acceptance in the United States among coal developers in the last two years. Today, over half the new coal projects proposed in some Midwestern states would use gasification to produce electricity, methane, fertilizer, and low-sulfur diesel fuel from coal. These projects include:

- Two 629 MWe IGCC plant to be built by the nation's largest utility, American Electric Power Company (AEP), in Ohio and West Virginia scheduled to be operational in 2010;
- 600 MWe IGCC plant proposed by the nation's fourth largest utility, Cinergy, near Edwardsport, Indiana;
- 630 MW IGCC plant proposed by Tondu in Texas;
- 630 MW IGCC plant proposed by Energy Northwest in Washington
- 330 MW IGCC plant proposed by Summit in Oregon,
- Three repowering projects to take old PC plants and convert them to IGCC by NRG in CT, DE, and NY. Each would be 630 MW
- Two 630 MW IGCC plants proposed by the ERORA Group (one in Illinois and one in Kentucky) and
- Two 606 MWe IGCC in Hoyt Lake Minnesota by Excelsior Energy

Other gasification projects include Power Holdings in Illinois and Peabody in Illinois, both of which would make methane from coal; Rentech in Illinois which would make fertilizer from coal, and Baard Energy in Ohio that would produce F-T diesel from coal, and a variety of coal to diesel projects in the West and Midwest. The figure below illustrates the range and locations of gasification projects across the United States[89]:

8, 2003). (p) **APPENDIX 16**. Hearing Officer's Report and Recommended Secretary's Order, Sierra Club, et al. v. Environment & Pub. Prot. Cabinet, File Nos. DAQ-26003-037 & DAQ-26048-037 (Environmental and Public Protections Cabinet, Commonwealth of Kentucky 2005) (EXCERPTS). (q) **APPENDIX 17**. In re Air Quality Permit for the Roundup Power Project (Permit No. 3182-00), Case No 2003-04 AQ (MT BER, June 2003). (r) **APPENDIX 18**. Letter from Richard L. Goodyear, New Mexico Environment Department to Mr. Larry Messinger, Mustang Energy Corporation, L.L.C. (December 23, 2002). (s) **APPENDIX 19**. Letter from Raj Solomon, New Mexico Environment Department to Ms. Diana Tickner, Vice President, Peabody Energy (Septemb er 16, 2005). (t) **APPENDIX 20**. West Virginia DAQ, Longview, Permit No. R-14-0024, Response to Comments 2 (Comments Received Between October 1, 2003 and January 14, 2004)(EXCERPTS). Most of these documents are available at www.catf.us/advocacy/legal/BACT_LAER.

[89] Phil Amick, "Experience with Gasification of Low-Rank Coals," presented at Workshop on Gasification Technologies, Bismark North Dakota, June 28, 2006.

QuickTime™ and a
TIFF (LZW) decompressor
are needed to see this picture.

Two full scale commercial IGCC electric generating units are in operation in the United States: Tampa Electric Company's 262 MW unit at the Polk plant in Florida and Cinergy's 192 MW unit at the Wabash River plant in Indiana, which both rely on coal as a fuel source.[90] Two other coal-based IGCC plants operate in Europe, NUON/Demkolec is a 253 MW plant in the Netherlands, and ELCOGAS in Spain is 298 MW.[91] IGCC units can be constructed with multiple gasifiers to achieve unit availability at levels comparable to those of conventional baseload facilities. For instance, the Eastman Chemical plant in Kingsport, Tennessee has utilized a dual-gasifier design to produce chemicals from syngas and has experienced 98 percent availability since 1986.[92]

Worldwide there are 131 gasification projects in operation with a combined capacity equivalent to 23,750 MW of IGCC units.[93] An additional 31 projects are planned that would increase this capacity by more than 50 percent.[94] Although not all of these projects produce electricity from coal, they demonstrate widespread commercial application of gasification technology for fuel processing, one of two key components of an IGCC plant. The second component is a combined

[90] Resource Systems Group, Inc., EPIndex. See www.epindex.com
[91] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Dec 2002, Table 1-7, page 1-26.
[92] Smith, R.G., "Eastman Chemical Plant Kingsport Plant Chemicals from Coal Operations,1983-2000," 2000 Gasification Technologies Conference.
[93] Simbeck, Dale, SFA Pacific Inc. Gasification Technology Update, presented to the European Gasification Conference, April 8-10, 2002. The total capacity is based on output of synthesis gas. Many of these projects produce chemicals in addition to or instead of electricity.
[94] Id.

cycle electricity generating system, which is now commonplace for new natural gas fired power plants.

IGCC units are available from major well-known vendors. Coal gasification equipment is available from GE, Shell, and ConocoPhillips. The National Coal Council, in a May 2001 report, confirms that IGCC is "viable, commercially available technology."[95] The Center for Energy and Economic Development (CEED) states that, "IGCC technology is available for deployment today."[96]

Step 2. Eliminate Technically Infeasible Options.

Conclusion: IGCC is a Technically Feasible Option for the DREF.

This step of the BACT analysis eliminates options based upon physical, chemical, and engineering principles that would preclude the successful use of the control option. Two issues appear to be uncontroversial with respect to IGCC technology. They are:

1) The design fuel for the DREF poses no technical barrier for using IGCC. As discussed in the attached Affidavit from John Thompson, gasification has been extensively used with subbituminous coals in the United States.

2) Water use poses no barrier IGCC deployment at the DREF site. That's because an IGCC plant uses approximately one-half to two-third less water than a pulverized coal plant.[97]

3) Plant Size: The 1,500 MW DREF facility would be larger than any IGCC plant in the nation. The Wabash, Polk, ELCOGAS, and NUON plants are all roughly 270 MW. Existing IGCC plants in Italy are 500 –600 MW, and IGCC plants in Europe (Nuon Magnum) will be 1200 MW. Mesaba One and Two would be 1212 MW (subbituminous coal) To scale up an IGCC plant to 1336MW would involve 5 gasifier trains, consisting of a gasifier, combustion turbine, and HRSG. The addition of more trains does not pose a technical barrier. In Italy, refinery IGCC plants operate at more than 500 MW, which consist of two trains and a spare gasifier. Moving to 5 trains and a spare is a natural extension of previous plants.

4) Availability: IGCC plants have demonstrated availabilities of 85% for single train gasifiers in the United States. As described more fully in the affidavit by John Thompson, Italian IGCC plants are achieving greater than 90% availability with and without a spare gasifier.. Therefore, plant availability poses no technical barriers for an IGCC plant at the DREF site.

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[95] National Coal Council, Increasing Electricity Availability from Coal-Fired Power Plants in the Near Term, p. 20 (May 2001).
[96] See www.ceednet.org/fueling/investing.asp
[97] Major Environmental Aspects of Gasification-Based Power Generation Technologies, U.S. DOE/NETL, December 2002 at page 2-61.

Step 3. Rank Remaining Control Technologies by Control Effectiveness

Conclusion: IGCC is the Top Ranked (i.e. Lowest Emission Rate) Control Technology.

The coal gasification fuel-processing step in IGCC power plants results in superior environmental performance and lower emissions compared to the pulverized coal technology that is proposed for the DREF. Gasifying coal at high pressure prior to combustion facilitates removal of pollutants that would otherwise be released into the air.

Attached to these comments is an affidavit by John Thompson that summarizes recent IGCC air permit applications and air permits. The table below summarizes the findings:

Table 2: Summary of Recent IGCC Permits and Proposed Permit Levels

	Approved Permit			Application Filed, Draft Permit Not Issued Yet								
Pollutant	**Global Energy Lima, Oh, 590 MW**	**Kentucky Pioneer Energy, KY**	**Wisconsin Electric Elm Road, 600 MW**	**ERORA Cash Creek, KY, 630 MW**	**Southern Illinois Clean Energy Complex, IL, 640 MW & 110 MMSCF methane**	**ERORA, Taylorville, IL 630 MW**	**Nueces, TX, 600 MW**	**Energy Northwest, WA, 600 MW**	**AEP, OH, 629 MW**	**AEP, WV, 629 MW**	**Mesaba One (606 MW), Mesaba Two (606), MN,Total 1,212 MW**	**Duke, Edwardsport, IN, 630 MW**
	lb/MMBtu	**lb/MMBtu**	**lb/MMBtu**	**lb/MMBtu**	**lb/MMBtu**	**lb/MMBtu**	**lb/MMBtu**	**lb/MMBtu**	**lb/MMBtu**	**lb/MMBtu**	**lb/MMBtu**	**lb/MMBtu**
SO_2	0.021	0.032 - 3 hr ave	0.03 -24 hr ave	0.0117 -3 hr ave	0.033 -30 day ave	0.0117 -3 hr ave	0.019	0.016 -3 hr ave	0.017	0.017	0.025	Repower, net from BACT
NOx	0.097	0.0735 -3 hr ave	0.07 (15 ppmdv) -30 day ave	0.0246- 24 hr ave	0.059 -30 day ave	0.0246 -24 hr ave	0.019	0.012 -3 hr ave	0.057	0.057	0.057	Repower, net from BACT
Mercury			.56 x 10- 6	.197 x10-6 (1)	.547 X10-6	.19 x 10- 6 (1)	1.825 x10-6	1.1 x10-5			90% removal .026 tons Phase I and II total	.008 tons/yr
PM	0.01	.0.011	0.011 (backhalf)				0.015	0.001			0.009	18.1 lbs/hr
PM10			0.011 (backhalf)	0.0063 -3 hr ave (filterable)	0.00924 (filterable)	0.0063 -3 hr ave (filterable)	0.014		.006 (filterable)	.006 (filterable)		
VOCs	0.0082	0.0044	0.0017 -24 hr ave (LAER) (3)	0.006 -24 hr ave	0.0029	0.006 -24 hr ave	0.004	0.003	0.001	0.001	0.0032	1.4 ppmvw
H_2SO_4			0.0005 -3 hr ave	0.0026 -3 hr ave	0.0042 -30 day ave	0.0026 -3hr ave	0.0001		98 tons/yr	98 tons/yr		
CO	0.137	0.032 -3 hr ave	.030 -24 hr ave	0.036 -24 hr ave	0.04 -30 day ave	0.036 -24 hr ave	0.04	0.036	0.031	0.031	0.0345	15 ppmvd
Lead			0.0000257									
Fluorides(2)												
Sulfur Control Technology	MDEA	MDEA	MDEA	Selexol	MDEA	Selexol	Selexol	Selexol	Selexol	Selexol	MDEA	Selexol
NOx Control Technology	Diluent injection	Diluent injection	Diluent injection	Diluent/SCR	Diluent injection	Diluent/SCR	Diluent/SCR	Diluent/SCR	Diluent injection	Diluent injection	Diluent injection	Diluent/SCR

(1) Application estimates this emission limit but does not proposed an emission limit

(2) No limit established. Fluorides from IGCC plants are below PSD significance

(3) Polk IGCC also has this emission rate effective July 2003 as set by BACT.

Table 2 shows the emission rates for IGCC plants permitted since 2001 and recently filed air permit applications for proposed IGCC plants.

Table 2 shows several trends:

1) The majority of IGCC plants proposed in the last 12 months have sought to control sulfur using Selexol, a more effective control strategy than MDEA. These plants include:

   - AEP in Ohio (application filed Oct 2006)
   - AEP in W Virginia (application filed Oct 2006)
   - Northwest Energy (application filed September 2006)
   - Tondu in Texas (application filed September 2006)
   - Duke in Indiana (application filed August 2006)
   - ERORA (revised application filed June 2006)
   - ERORA in Illinois (revised application filed March 2006)

   Only one air permit application filed in the last 12 months, Mesaba (filed June 2006) uses the less effective MDEA.

   Selexol effectively removes sulfur levels to between .00117 to .0019 lb/MMBtu heat input into the gasifier.

2) A narrow majority of IGCC plants that have filed applications in the last 12 months include SCRs to control NOx. These include:

   - Northewest Energy
   - Tondu
   - ERORA in Illinois
   - ERORA in Kentucky
   - Duke in Indiana

The NOx emission rates for SCR controlled IGCC plants is .012 - .025 lb/MMBtu based upon heat into the gasifier.

These trends toward Selexol and SCR are occurring faster than USEPA predicted in its recently released (July 2006) report, "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies." The July 2006 EPA report assumed that MDEA and diluent injection would be BACT for the near-term. Clearly, the market has responded with technology faster than the USEPA report anticipated.

Table 3 summarizes the range of recently filed air permit for IGCC plants (filed in the last 12 months plus the most recently issued air permit for We Energies in Wisconsin) and compares them to the proposed DREF permit.

Table 3: Emission Rates of Proposed DREF Permit Compared to IGCC Requested Rates

	DREF	IGCC			
	Proposed Emission Rates[a]	Sulfur control using MDEA	Sulfur control using Selexol	Nitrogen control using diluent injection	Nitrogen control using both diluent injection and SCR
	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)
SO2	0.06	.025-.033	.0117-.019		
NOx	0.06			.057-.07	.012-.025
PM (filterable)	0.010		0.0063-0.014		
PM10 (total)	0.020				
CO	0.10		0.03-0.04		
Sulfuric Acid Mist	0.0040		0.0005-0.0042		
VOC	0.0030		0.001-0.006		
Hg	No limit		0.00000019-0.00000056		

[a]All proposed DREF emission rates listed would apply on a 24-hour average basis with the exception of the limit for sulfuric acid mist which would apply on a 3-hour average basis.

As Table 3 shows, recently all permitted and proposed IGCC plants have lower limits for SO2, NOx, PM (filterable), and CO, and some facilities also have lower sulfuric acid mist and VOC limits. The SO2 removal rates correspond to over 99.2% with Selexol and around 98% -99% with MDEA. The DREF removal rate, in contrast, is only about 96.8%.

The differences between IGCC with Selexol and SCR and DREF emission rates are vast. An IGCC plant can be expected to emit approximately one-third as much sulfur dioxide, one-third as much nitrogen oxide, about 40% less PM, two-thirds less CO, and significantly less sulfuric acid mist and VOCs.

Sithe incorrectly estimates the emissions of an IGCC plant by assuming that the likely control devices would involve MDEA and diluent injection, using higher emission rates for other criteria pollutants than current BACT applications show, and assuming the IGCC plant to be less efficient than it actually would be.

Step 4. Evaluate the Most Effective Controls and Document the Results.

<u>Conclusion: Evaluation of Economic, Environmental and Energy Impacts Confirms that IGCC is the Effective Control Technology.</u>

Economic Impacts:

1. Heat Rate - In October 2005, ConocoPhillips presented a paper at the Gasification Technologies Council Conference entitled, "E-Gas Applications for Sub-bituminous Coal." The report describes the design, environmental performance and costs for a 555 MW (net) IGCC plant at an altitude and coal heat content comparable to Desert Rock.

Sithe also assumed ConocoPhillips gasifiers in its September 2005 report to Region 9. The table below compares Sithe's estimate of IGCC design at Desert Rock to design in the ConocoPhillips presentation (scaled to the same size and including spare):

<u>Table 4</u>

	Design Presented by Sithe (1)	Design based on CP Presentation (2)	Design based on CP Presentation (2)
Spare	With spare	No Spare	With Spare
Net Power (MW)	1366	1387	1387
Net Heat rate (HHV)	9775	9075	9075
altitude	5415 MSL	5000 MSL	5000 MSL
coal heat content (Btu/lb)	8953	8340	8340
Number of gasifiers	12	10	12
Number of Turbines	7 GE7FA	5 SGT6-5000F	5 SGT6-5000F
Number of Air Separation Units	6	not specified	not specified
Pollution controls	not specified	Selexol/SCR	Selxol/SCR

Notes
1. "Desert Rock Energy Project Design Comparison to Integrated Gasification Combined Cycle and Circulating Fluidized Bed Combustion," ENSR Corporation, September 2005, at 4-9.
2. "E-Gas Applications on Sub-bituminous Coals," Presentation by ConocoPhillips, October 2005.

As the table shows, the Sithe report significantly overstates the heat rate and the number of turbines needed for an IGCC plant at the Desert Rock site.

USEPA estimates the heat rate of an IGCC plant to be even lower on subbituminous coals. In its report, "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined

Cycle and Pulverized Coal Technologies," USEPA estimates the heat rate of a supercritical PC as 9,000 Btu/kWh and an IGCC as 8,520 Btu/kWh.[98]

An IGCC is either more efficient or nearly equivalent to a supercritical PC plant at the Desert Rock location using coal with a heat content of 8,900 Btu/lb. The Sithe report incorrectly reaches the wrong conclusion

2. Capital Costs and Cost of Electricity
Sithe estimates that an IGCC at the Desert Rock site would cost $250/kW to $400/kW higher than a PC plant. Sithe estimates that the cost of electricity using IGCC at the Desert Rock location would be between $3.5/MWh and $6/MWh. According to the affidavit filed by John Thompson, these cost estimates represents a conservative upper bound for both the capital cost premium for an IGCC plant at the Desert Rock location and the added cost of electricity. As noted in the affidavit, the costs could be lower due the acquisition by Siemens of the Future Energy gasification technology that is well adapted to inexpensively gasify low-rank coals, rising PC costs, and advances in the IGCC learning curve.

In any case, these added costs are small compared to the enormous reduction in criteria pollutants emitted if the Desert Rock plant employed IGCC technology, As described more fully in the Thompson affidavit, the table below shows the emissions for Desert Rock as a conventional plant, Sithe's estimates for an IGCC at Desert Rock, and more realistic estimates for heat rate and emission limits based upon more recent applications.

[98] USEPA, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, July 2006, at page ES-7.

	Estimated by Sithe			
Parameter	Desert Rock	IGCC	Corrected IGCC	Units
Average Heat Rate	8792	9755	9075	Btu/kw
SO2 Emissions	0.06	0.0229	0.0117	lb/MMBtu
SO2 emissions	2998	1272	590	ton/yr
IGCC benefit		Decrease 1726	Decrease 2408	ton/yr
NOx emissions	0.06	0.06	0.012	lb/MMBtu
NOx emissions	2998	3333	605	ton/yr
IGCC benefit		Increase 335	Decrease 2393	ton/yr
PM emissions	0.01	0.01	0.0063	lb/MMBtu
PM emissions	500	556	317	ton/yr
IGCC benefit		Increase 56	Decrease 183	ton/yr
VOC emissions	0.003	0.003	0.001	lb/MMBtu
VOC emissions	150	167	50	ton/yr
IGCC benefit		Increase 13.5	Decrese 100	ton/yr
CO emissions	0.1	0.04	0.03	lb/MMBtu
CO emissions	4997	2222	1513	ton/yr
IGCC benefit		Decrease 2775	Decrease 3484	ton/yr
Sulfuric Acid Mist e	0.004	0.0023	0.0005	lb/MMBtu
Sulfuric Acid Mist e	200	128	25	ton/yr
IGCC benefit		Decrease 72	Decrease 175	ton/yr
Mercury emissions	9.28E-06	2.52E-06	1.90E-07	lb/MMBtu
Mercury emissions	103	29	19	lb/yr
IGCC benefit		Decrease 75	Decrease 84	lb/yr

Sithe incorrectly calculates the main pollutant benefit (as measured by tons) as a 1,726 ton per year of SO2. In fact, the total tons of pollutants removed are more nearly 8,700 tons/yr. As a result, Sithe incorrectly calculates the benefit computes the incremental cost of $23,000 to $40,000 per ton of SO2 controlled. A more plausible incremental value ranges between $4,500/ton and $7,600/ton, a range considered cost effective.

Environmental Issues: Greenhouse Gases: IGCC also has several other environmental advantages beyond its reductions in criteria pollutants. Carbon dioxide (CO_2) removal is easier and less expensive at IGCC units than at other coal-fired plants. Because an IGCC plant is typically more efficient in terms of heat rate compared to a PC unit,[99] CO_2 emissions -- the primary greenhouse gas responsible for anthropogenic contributions to global warming -- are also reduced by that same amount.

Furthermore, IGCC has an option to make even deeper cuts in carbon dioxide that conventional coal plants cannot do. The CO_2 in the syngas can be captured and sequestered at a fraction of the cost of post-combustion carbon capture and sequestration other coal plants.

The reduced CO_2 emissions rate has important environmental benefits in addressing the urgent problem of global climate change and also reduces increased costs due to future climate change regulations.

[99] USEPA, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, July 2006, at page ES-7..

Environmental Issues, Solid Wastes: The waste leaving an IGCC plant is vitrified, thereby potentially reducing some of the solid waste disposal issues associated with coal combustion. Indeed, IGCC plants produce 30-50% less solid waste than PC plants.[100] Also, because of the better heat rate associated with IGCC, less coal would have to be mined when compared to conventional coal plants.

Energy Issues: As noted above, IGCC plants are 10-15% more efficient than PC plants. IGCC is ranks above PC when energy issues are addressed.

Step 5. Select BACT

Conclusion: IGCC is BACT for the DREF

In summary, IGCC is clearly an available method, system and technique for producing electricity from the subbituminous coal to be utilized at the DREF and thus must be fully and fairly evaluated in the BACT analysis for this facility. Our analysis described above and supported by the attached Thompson Affidavit demonstrates that, had EPA properly evaluated IGCC in the DREF BACT analysis, IGCC would have been the selected technology for the DREF facility.

4. THE PROPOSED BACT EMISSION LIMITS FAIL TO REFLECT THE MAXIMUM LEVEL OF CONTROL THAT CAN BE ACHIEVED

The NO_x Emission Limit Does Not Reflect BACT

EPA has proposed a NO_x BACT limit of 0.06 lb/MMBtu on a 24-hour average basis. (Condition IX.E.2. of the proposed permit). This is the same as what was proposed by Sithe for the DREF. (May 2004 DREF PSD Permit Application, at 4-9). However, neither the DREF PSD Permit Application nor the EPA's AAQIR provide any discussion or analysis of whether this emission limit reflects the maximum degree of reduction of NO_x that can be achieved at DREF. Instead, Sithe has proposed an emission limit slightly lower than what is typically proposed as NO_x BACT at new coal-fired power plants today, and claims that it reflects the lowest achievable emission rate (LAER). *Id.*

While this proposed NO_x emission limit is one of the lowest emission limits proposed for any new coal-fired power plant, it does not necessarily reflect the maximum degree of reduction in NO_x emissions that can be achieved as required by the definition of BACT at 40 C.F.R. §52.21(b)(12). Vendor literature for ultra low NO_x burners shows that extremely low NO_x emission rates can be achieved from ultra low NO_x burners. (See www.babcock.com). For example, a Babcock & Wilcox study of a retrofit of ultra low NO_x burners at the 690 MW W.A. Parrish power plant showed that a NO_x emission rate of 0.17 lb/MMBtu was achievable **at full**

[100] Major Environmental Aspects of Gasification-Based Power Generation Technologies, US DOE, December 2002, Table 1-7, Page 1-27.

load.[101] Further, according to Babcock & Wilcox, commercial SCR installations have shown that 90% NO_x reductions can be achieved with low ammonia slip.[102] Indeed, Babcock & Wilcox states that up to 95% NO_x control can be achieved with SCR. Thus, considering 90% control and a NO_x emission rate exiting the boiler of 0.17 lb/MMBtu, a NO_x emission rate of 0.017 lb/MMBtu should be considered to reflect the maximum degree of reduction achievable.

While Sithe did include a brief discussion in its May 2004 PSD Permit Application regarding the W.A. Parrish power plant in Texas, which also uses selective catalytic reduction (SCR) in addition to the ultra low NO_x burners and which is required to meet a NO_x emission limit of 0.03 lb/MMBtu (May 2004 DREF PSD Permit Application at 4-4 to 4-5), Sithe discounted this lower NO_x emission rate on various points including that the facility will be using Powder River Basin coal, that this facility was operating in a nonattainment area, and that compliance with this emission rate had not yet been demonstrated in practice. However, Sithe failed to provide sufficient detailed information as to why this or similar emission limits could not be met with the coal that is currently planned for DREF. The fact that the source was operating in an ozone nonattainment area is irrelevant. Even lowest achievable emission rate (LAER) determinations required under nonattainment NSR permits are to be considered in the BACT analysis. See October 1990 draft New Source Review Workshop Manual at B.5. While the area that DREF is proposing to locate is not currently an ozone nonattainment area, the northwestern part of New Mexico has monitored extremely high levels of ozone. As discussed elsewhere in this comment letter and in an attachment, Sithe has failed to verify whether the DREF will cause or contribute to ozone NAAQS violations in the region. Further, the state of New Mexico has entered into an Early Action Compact (EAC) with EPA as a pre-emptive move to avoid being designated as a nonattainment area for ozone.[103] Thus, although the DREF is not formally subject to a NO_x LAER determination under the New Source Review rules, EPA is bound to consider environmental impacts in determining the maximum degree of NO_x reduction achievable and in setting the NO_x BACT limits. Such environmental impacts should include that the area is essentially a borderline ozone nonattainment area. Thus, the lowest emission rates and maximum degree of NO_x emission reductions must be evaluated by Sithe in its BACT analysis.

Further, whether compliance with this emission rate had been achieved is not as relevant in the BACT analysis as whether there is sufficient information such as manufacturing data and engineering estimates showing that the emission rate *can* be achieved. See, e.g., New Source Review Workshop Manual (October 1990 draft) at B.24. Rather than attempt to discount this data for the W.A. Parrish plant, Sithe instead should have evaluated the lowest level of NO_x

[101] See Bryk, S.A., R.J. Kleisley, A.D. LaRue, H.S. Blinka, R.M. Gordon, and R.H. Hoh, First Commercial Application of DRB-4Z™ Ultra Low-NOx Coal-Fired Burner, presented at POWER GEN International 2000, November 2000. (**Attachment 14**).

[102] See Bielawski, G.T., J.B. Rogan, and D.K. McDonald, How Low Can We Go? Controlling Emissions in New Coal-Fired Power Plants, Presented to the U.S. EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Symposium: "The Mega Symposium," August 2001. (**Attachment 15**.)

[103] December 20, 2002 Early Action Compact Memorandum of Understanding, available at http://www.nmenv.state.nm.us/aqb/ozonetf/index.html.

emissions that *could* be met with state-of-the-art low NO_x burners at DREF, and then evaluated the maximum degree of reduction of NOx that could be achieved with the addition of SCR.

Sithe did not provide information on the NO_x emission rate that is expected to be emitted from the DREF boilers considering the low NO_x burners. The permit analysis for the recently issued Intermountain Power Plant Unit 3 PSD permit indicated that the NO_x emission rate expected from low NO_x burners at that unit, which would burn western bituminous coal from Utah, would be 0.35 lb/MMBtu. Attached hereto and listed as **Attachment 16** in the attached exhibit list hereto, March 22, 2004 Modified Source Plan Review for Intermountain Power Service Corporation at 9. Assuming that DREF would achieve a similar or better level of NO_x control with its planned low NO_x burners (and a lower emission rate is more likely considering its planned supercritical boiler), that would mean a 0.06 lb/MMBtu NO_x emission rate reflects at best an 82.9% reduction in NO_x from the SCR. Yet, vendors have indicated that at least 90% NO_x control can be consistently achieved with SCR systems.

In addition, a recently issued permit for a coal-fired power plant set a NO_x emission limit that reflects 0.05 lb/MMBtu on a 24-hour basis. Specifically, the Trimble County LG&E coal-fired power plant, a 750 MW unit with a supercritical pulverized coal boiler with maximum heat input capacity of 6,942 MMBtu per hour, was issued a permit on November 17, 2005 that includes a NO_x limit of 4.17 tons per calendar day. November 17, 2005 Title V Air Quality Permit for the Trimble County Generating Station (Permit Number V-02-043 Revision 2), at 27-28 (Attached hereto and listed as **Attachment 17** in the attached exhibit list hereto). When the unit is operating at maximum heat input capacity, this equates to a NO_x limit of 0.05 lb/MMBtu per 24-hour period. This facility will burn eastern bituminous coal or a blend of western subbituminous and eastern bituminous coal. While this NO_x emission limit was not a BACT limit, it was to reflect "BACT type controls with similar emissions levels." *Id.* at 27. Further, PSD permit applicants are not bound only to what has been required as BACT in determining an emission limit reflecting the maximum degree of emission reduction that can be achieved. Instead, the permit applicant and permitting authority must examine <u>all</u> of the relevant data available, and evaluate the maximum degree of reduction that can be achieved as the top level of BACT to be evaluated first.

Thus, for all of the above reasons, Sithe and EPA have not adequately evaluated BACT for NO_x at DREF. Sithe and EPA failed to show that the proposed emission limit reflects the maximum degree of NO_x reduction that can be achieved. Further, Sithe and EPA failed to indicate the level of NO_x reductions expected of the pollution control equipment evaluated and failed to evaluate the varying levels of control that the selected control equipment can achieve based on vendor information and/or practical experience. Consequently, EPA must determine through a true and thorough top-down analysis the level of control that reflects the maximum degree of NO_x reduction that can be achieved at DREF and impose a NO_x emission limit that reflects that maximum degree of NO_x control.

<u>The DREF Permit Record Does Not Support the SO_2 Emission Limit As Reflecting BACT</u>

EPA has proposed an SO_2 BACT emission limit of 0.06 lb/MMBtu (24-hour average). (Condition IX.D.2 of the proposed permit). EPA also proposed a 3-hour average SO_2 emission limit of 612 lb/hr (Condition IX.D.1. of the proposed permit). At maximum hourly heat input capacity, this hourly SO_2 limit would equate to 0.09 lb/MMBtu. There are two major problems with this BACT determination. First, the proposed BACT limit is unsupported in the record and apparently arises out of a flawed BACT analysis. Second, the proposed level does not correspond to the maximum degree of reduction that is achievable, as required by the plain language definition of BACT.

Improper BACT Analysis

The NSR Manual sets out a six step process for determining BACT. NSR Manual, Section 3. Step 4 of this process is missing. If the top control option, e.g., a 98% efficient scrubber (AAQIR, Table 4), is not selected, Step 4 requires a case-by-case quantitative analysis of energy, economic, and environmental impacts, comparable to Table B-3 in the NSR Manual. *Id.* at B.28. This analysis is missing and in its place is an unsupported assertion that Sithe has selected a SO_2 BACT limit that is lower than any formerly permitted level, thus corrupting the technology forcing nature of BACT and the obligation to set a limit that is based on the maximum degree of reduction that is achievable.

The Application and AAQIR report an SO_2 control range for wet scrubbing of 90% to 98%. AAQIR, Table 4; and May 2004 DREF PSD Permit Application, Table 4-2. However, neither indicates what levels of SO_2 control were evaluated for a wet scrubber at DREF, the uncontrolled SO_2 emission rate, the control efficiency that was ultimately determined to be achievable at DREF, and the basis for the BACT determination. This information is needed to evaluate whether the limits reflect the maximum degree of SO_2 reduction that can be achieved with a wet scrubber. Instead, Sithe simply compared its proposed BACT limit to other recently issued permits for coal-fired power plants to show that its SO_2 limit would be lower. In determining BACT for SO_2, the emission limit must be based on the maximum degree of reduction that can be achieved, taking into account energy, environmental, and economic impacts. In the top-down BACT review process relied on by the EPA, the top level of control must be evaluated first. See EPA's New Source Review Workshop Manual, October 1990 Draft, at B.1., B.23-B.25. The record contains no evidence that the top level of control, 98%, was evaluated and if it was, why it wasn't chosen.

Sithe's permit application for DREF indicates wet scrubbers can remove up to 98% of the SO_2 in the flue gas. May 2004 DREF PSD Permit Application at 4-11. However, the control efficiency corresponding to the selected BACT limit of 0.06 lb/MMBtu is not disclosed, making it impossible for reviewers to determine if the limit corresponds to the maximum degree of SO_2 reduction. The SO_2 control efficiency for the "system" (as opposed to the scrubber) can be backcalculated from coal quality data in the Application, but the public should not be left to second guess the agency.

This backcalculation suggests that the SO_2 BACT limit of 0.06 lb/MMBtu assumes about 97% of the sulfur in coal is removed between the coal pile and the stack.[104] Some of this sulfur is removed with pyrites at the pulverizer. Some is removed with the bottom ash and fly ash. Some exits the stack as sulfate. Some is converted into sulfuric acid mist.[105] Assuming about 15% of the sulfur in the coal appears as SO_2 at the scrubber inlet, a typical number used in BACT analyses, the SO_2 control efficiency of the scrubber selected as BACT is about 96%. This

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[104] The Application indicates that the design fuel has 0.82% S and a higher heating value of 8,910 Btu/lb. May 2004 DREF PSD Permit Application, Table 2-2. Thus, the uncontrolled SO2 content of the coal is: (0.82/8910)(20,000) = 1.84 lb/MMBtu. The implicit control efficiency is: 100(1-.06/1.84) = 96.7% based on HHV.

[105] R. Evers, V.E. Vandergriff, and R.L. Zielke, Field Study to Obtain Trace Element Mass Balances at a Coal-fired Utility Boiler, Report EPA-600/7-80-171, October 1980, Calculated at 15% from S data in Tables 6, 7, 10 & 11. See also AP-42, Table 1.1-3, note b. (**Attachment 18**).

control level is less than the upper value of 98% reported in the DREF PSD Permit Application (Table 4-2) and AAQIR (Table 4) for the scrubber alone. A 2% increase in SO_2 control efficiency would halve SO_2 stack emissions. The DREF PSD Permit Application and AAQIR fail to provide any basis for not selecting a 98% efficient wet scrubber, the top control level that both Sithe and the EPA reported. The top-reported SO_2 control efficiency of 98% should have been explicitly evaluated because 98% control has been determined to be BACT for SO_2 in several recent coal-fired power plant permitting cases, including Thoroughbred in Kentucky and Prairie State and Dallman 5 in Illinois. NSR Manual at B.23.

Higher SO_2 Control Efficiencies Are Achievable

Further, 98% is not the highest achievable SO_2 control efficiency for low sulfur coal similar to Navajo's coal. The Application and AAQIR rely on other permitted sources, corrupting the BACT process. Many other sources of information, other than just permitted levels, must be consulted to determine BACT. See, e.g., October 1990 draft New Source Review Workshop Manual at B.11. A higher control efficiency would have been reported had a thorough review of available sources been conducted. The top control option is a wet FGD designed to achieve 99%+ SO_2 control. This level of control has been achieved at the Mitchell Station in Pennsylvania using magnesium enhanced lime, a type of wet FGD. Attached hereto and listed as **Attachment** 19 in the attached exhibit list hereto. It has also been achieved at several coal-fired power plants in Japan and is proposed for several U.S. coal fired power plants.

Chiyoda's bubbling jet reactor (a type of wet FGD) has consistently achieved >99% SO_2 removal during long-term operation at the Shinko-Kobe power plant in Japan. This facility consists of two 700-MW coal-fired utility boilers. The wet FGD was designed to achieve 0.014 lb SO_2/MMBtu (9 ppmv at 3% oxygen) on an instantaneous basis and has consistently exceeded this level while treating gases with inlet SO_2 concentrations within the range proposed for DREF (1.78 lb SO_2/MMBtu compared to 1.84 lb SO_2/MMBtu for DREF).[106] This technology has been guaranteed by Chiyoda to achieve 99% SO_2 removal on three coal-fired boilers in Japan.[107] It also has been demonstrated in the U.S. at the University of Illinois's Abbott power plant and Georgia Power's Plant Yates[108] and recently was licensed for use on several additional plants in the US, including Plant Bowen in Georgia, Dayton Power & Light's Killen and Stuart plants, and AEP's Big Sandy Unit 2, Conesville Unit 4, Cardinal Units 1 and 2, and Kyger Creek, among others.[109] Black & Veatch and Southern Company are both U.S. licensees.

[106] Yasuhiko Shimogama, Hirokazu Yasuda, Naohiro Kaji, Fumiaki Tanaka, and David K. Harris, Commercial Experience of the CT-121 FGD Plant for 700 MW Shinko-Kobe Electric Power Plant, Paper No. 27, presented at MEGA Symposium, Air & Waste Management Association, May 19-22, 2003 (**Attachment 20**).

[107] CT-121 FGD Process – Jet Bubbling Reactor, http://www.bwe.dk/fgd-ct121.html. (**Attachment 21**).

[108] Emission-control Technologies Continue to Clear the Air, Power, May/June 2002.

[109] Chiyoda Licenses Its Flue Gas Desulfurization Technology in USA Newly for 5 Coal-Fired Generation Units, Press Release, May 2, 2005 (**Attachment 22**); Chiyoda Licenses its Flue Gas Desulfurization Process in USA for Georgia Power Owned 4 FGD Units, January 26, 2005 (**Attachment 23**).

Mitsubishi, a vendor of scrubber systems, reports it has guaranteed SO_2 removal efficiencies up to 99.8 percent, including four coal-fired boilers.[110, 111, 112]

The Application and AAQIR do not acknowledge control efficiencies greater than 98%. The NSR Manual specifically states that technologies in application outside of the United States should be considered in the BACT analysis. NSR Manual, p. B.11.

Finally, a recent Lake Michigan Air Directors Consortium ("LADCO") and the Midwest Regional Planning Organization ("MRPO") presentation indicated that advanced FGD technologies could achieve 99.5% control for $1,240 to $2,875 per ton of SO_2 removed and wet FGD could achieve 99% SO_2 control for $1,881 to $3,440 per ton of SO_2 removed. Attached hereto and listed as **Attachment 27** in the attached exhibit list hereto. These costs are well within the range that EPA normally considers to be cost effective.

<u>Lower SO_2 Emission Limits Are Achievable</u>

Japan regulates SO_2 emissions to about 10 ppm (0.02 lb/MMBtu) from new industrial facilities locating in polluted areas. There are currently two Japanese vendors who supply wet FGD systems in the U.S. market that are able to achieve 99% SO_2 control on low sulfur coals. These are Chiyoda and Mitsubishi, as discussed supra. These two wet FGD systems are more cost effective, require less water and electricity, generate less wastes, and remove more mercury and particulate matter than the type of wet FGD selected for DREF. They do not have any adverse energy, environmental, or economic impacts.

This Japanese experience is supported by two facilities in the U.S. The U.S. EPA issued a PSD permit to AES Puerto Rico to construct and operate a 454-MW coal-fired CFB project. The permit requires the unit to meet an SO_2 limit of 0.022 lb/MMBtu or 9.00 ppmvd corrected to 7% oxygen on a 3-hour basis, compared to 0.09lb/MMBtu on a 3-hour basis and 0.06 lb/MMBtu on a 24-hour basis for DREF.[113] The much lower AES Puerto Rico limit has been achieved.[114] Further, Utah issued a permit for the Nevco Sevier project in October 2004. Its SO_2 limits are: 0.022 lb/MMBtu based on a 30-day average and 0.05 lb/MMBtu based on a 24-hour average. We are not advocating CFBs for DREF, but rather that the emission limits proposed for these CFB units should be included in the top down BACT analysis for PC boilers, as set out below.

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110 Jonas S. Klingspor, Kiyoshi Okazoe, Tetsu Ushiku, and George Munson, High Efficiency Double Contact Flow Scrubber for the U.S. FGD Market, Paper No. 135 presented at MEGA Symposium, Air & Waste Management Association, May 19-22, 2003, p.8, Table 4 (**Attachment 24**).

111 Yoshio Nakayama, Tetsu Ushiku, and Takeo Shinoda, Commercial Experience and Actual-Plant-Scale Test Facility of MHI Single Tower FGD, (**Attachment 25**).

112 http://www.mhi.co.jp/mcec/product/fgd.htm (**Attachment 26**).

113 U.S. EPA, Region 2, Second Revision to the Final Prevention of Significant Deterioration of Air Quality (PSD) Permit for the AES Puerto Rico Cogeneration Plant (AES-PRCP) – Administrative Permit Modification, August 10, 2004 (**Attachment 28**).

114 Memorandum from Donald G. Wright to John P. Aponte, U.S. EPA, Re: AES Puerto Rico Total Energy Plant – Review of the March 3, 2003 Stack Test Report (**Attachment 29**); Memorandum from Donald G. Wright to Francisco Claudio, U.S. EPA, Re: AES Puerto Rico Total Energy Project – Review of the October 2002 Test Report, February 3, 2003 (**Attachment 30**).

The Application rejects AES Puerto Rico, arguing that CFB "is a fundamentally different source type…" May 2004 DREF PSD Permit Application., p. 4-10. The underlying combustion method, CFB versus a PC boiler, is not determinative if the gas streams are similar and the same control technologies can be used. October 1990 draft New Source Review Workshop Manual, pp. B.10, B.11, B.16 ("The fact that a control option has never been applied to process emission units similar or identical to that proposed does not mean it can be ignored in the BACT analysis if the potential for its application exists."). The record contains no evidence that the gas streams from these two types of coal combustion technologies differ in any substantial way that would affect the achievable SO_2 control efficiency or emission limitation.

Further, the U.S. EPA in its rulemakings does not distinguish CFBs and PC boilers when establishing nationwide emission standards. See, for example, 70 FR 39104 (July 6, 2005); 70 FR 9706 (Feb. 28, 2005); and 63 FR 49442 (Sept. 16, 1998) and supporting dockets. Likewise, the National Park Service ("NPS") commented that limits achievable by CFBs should be evaluated for DREF and demonstrate why such limits cannot be met. The EPA's comments on the Longview, WV facility also recommended BACT limits based on two CFBs, Northampton and JEA Northside. Attached hereto and listed as **Attachment 31** in the attached exhibit list hereto.

The Application also argues that AES Puerto Rico is not applicable to DREF because the electricity markets differ in Puerto Rico and the U.S. May 2004 DREF PSD Permit Application, p. 4-11. However, these types of market issues and economic impacts to the permittee are considered in the top down BACT analysis process and have been explicitly rejected by the courts. See *Alaska v. United States EPA*, 244 F.3d 748 (9th Cir. 2002), aff'd, 537 U.S. 1186 (2003).

<u>The PSD Permit Must Also Specify a SO_2 Control Efficiency Requirement</u>

EPA must impose a SO_2 removal efficiency requirement in addition to an SO_2 BACT limit in terms of lb/MMBtu to ensure that the maximum degree of emission reduction is required at DREF. Such a requirement would ensure proper operation and maintenance of the scrubber regardless of the sulfur content in the coal. The predicted SO_2 increment violations at Mesa Verde National Park discussed further below and the visibility impacts of DREF at nearby Class I areas provide further basis for such a removal efficiency requirement reflective of what the wet scrubber can achieve. EPA Region VIII made this same comment to the Montana Department of Environmental Quality pertaining to the recently issued Roundup Power Plant PSD permit. Attached hereto and listed as **Attachment 32** in the attached exhibit list hereto.

Thus, for all of the above reasons and as shown in the Attachments provided, the SO2 BACT determination for DREF is significantly flawed.

<u>The PM and Total PM_{10} BACT Analyses Are Flawed</u>

EPA has proposed a PM (filterable) BACT limit of 0.010 lb/MMBtu and a total PM_{10} limit (filterable plus condensables) of 0.020 lb/MMBtu, which would both apply on a 24-hour average basis. Conditions IX.H.2. and I.2. of the proposed DREF permit. Both Sithe and EPA justified the PM BACT limit as "lower than the lowest emission level for a new coal-fired boiler (Wygen 2 in Wyoming) listed in EPA's RACT/BACT/LAER Clearinghouse or other reference materials discussed in the BACT analysis for NO_x and SO_2." See EPA's AAQIR at 26.

As discussed above regarding the NO_x and SO_2 BACT determinations, it is not sufficient to simply compare the proposed BACT limit to the BACT emission limits of other recently permitted coal-fired power plants. The PM/PM_{10} BACT analysis should also be based on a review of the maximum degree of emission reduction that can be achieved. And there is a significant amount of data available indicating that a greater degree of PM reduction, and a lower PM emission rate, can be achieved with a fabric filter baghouse.

Environmental Defense et al's April 29, 2005 comment letter to EPA on its proposed New Source Performance Standards revisions for steam generating units included as Exhibit 4 results from recent stack tests of Florida coal-burning steam generating units, which indicated that more than half of the units tested were meeting PM/PM_{10} emission rates of 0.0090 lb/MMBtu or lower, with the lowest emission rate achieved being 0.0004 lb/MMBtu at JEA Northside Unit 2. Environmental Defense also submitted PM/PM_{10} stack test data for Unit #2 of the Craig power plant and for the Northampton Generating Station as Exhibits 5 and 6 to their April 29, 2005 letter. We have attached all of these exhibits as **Attachment 33** on the attached exhibit list. The Craig Unit #2 data shows that, on average, the unit is emitting PM at 0.005 lb/MMBtu, which is significantly lower than the 0.010 lb/MMBtu PM emission rate proposed by EPA as BACT at DREF.

The Northampton facility, which has a total PM BACT limit of 0.0088 lb/MMBtu (a recently issued coal-fired power plant permit that EPA and Sithe failed to consider in their BACT review for DREF), is emitting both filterable PM and total PM at 0.0043 lb/MMBtu on average based on the stack test data included in Attachment 33. A copy of the permit for this facility is also included as **Attachment 34** on the attached exhibit list to this letter.

Thus, EPA and Sithe must revise the DREF PM and total PM_{10} BACT analyses to evaluate the maximum degree of reduction in these pollutants that can be achieved at DREF, which considers the data provided in this letter on what is actually being achieved in practice.

Further, EPA's proposed permit provision at Condition IX.T. that allows for a permit revision if, at the end of 18 months following startup, performance testing indicates that DREF is not achieving the total PM_{10} BACT limit of 0.020 lb/MMBtu emission limit is entirely inconsistent with the PSD regulations. Any relaxation of the PM_{10} BACT limit must be evaluated in another BACT analysis, and all modeling that relied on the proposed 0.020 lb/MMBtu BACT limit must be revised (which would include the determination of the DREF's PM_{10} significant impact area which defines which sources need to be included in cumulative modeling assessments, the Class I and II PM_{10} increment analyses, and the near-field and Class I area visibility analyses). Thus, EPA cannot allow the PM_{10} BACT limit to be revised without going through a PSD permit revision and without providing the public with the opportunity to review and provide comments on the revised BACT analysis and modeling analyses. Condition IX.T. of the proposed DREF permit must be removed.

EPA Must Make Clear that the Opacity Limit is a BACT Limit

EPA has proposed an opacity limit on the DREF boilers of not more than 10%. (Condition IX.J.1. of the proposed DREF permit). While we firmly support an opacity limit as a necessary requirement of the PSD permit, EPA must make clear that this opacity limit reflects a BACT opacity limit (consistent with the definition of BACT at 40 C.F.R. §52.21(b)(12) which indicates that BACT includes "a visible emissions limit"). The EPA's AAQIR should also include a discussion to support why the 10% opacity limit was chosen as representing BACT. It should be noted that several recently issued permits for coal-fired power plants have 10% opacity BACT limits, including Unit #3 of the Intermountain Power Plant in Utah[115], the Sevier CFB power plant in Utah,[116] and the Longview power plant in West Virginia, which is required to utilize PM CEMS to ensure compliance with its PM BACT limit *and* to meet a 10% opacity BACT limit.[117] EPA must set the opacity BACT limit as reflecting the maximum degree of reduction in opacity that is achievable, and compliance must be based on a continuous opacity monitoring systems (COMS) that will be required to be installed at DREF pursuant to acid rain requirements.

The H_2SO_4 Emission Limit Was Not Justified as Representative of BACT

EPA has proposed a sulfuric acid mist (H_2SO_4) emission limit of 0.0040 lb/MMBtu (Condition IX.K.2. of the proposed DREF permit). However, neither Sithe nor EPA provided a review of all of the control technologies that could be applied at DREF to achieve the maximum degree of reduction in H_2SO_4 emissions that could be achieved at the facility. Instead, Sithe indicated that, through the use of its proprietary technology using hydrated lime upstream of the baghouse to remove H_2SO_4 before it enters the wet scrubber, DREF's H_2SO_4 emission rate would be less than the H_2SO_4 emission limit required at the Thoroughbred Generating Station which will be equipped with a wet electrostatic precipitator (WESP) for H_2SO_4 control. May 2004 DREF PSD Permit Application at 4-22 to 4-23. EPA simply accepted Sithe's claim as sufficient information to justify its proposed 0.0040 lb/MMBtu permit limit as BACT. AAQIR at 29. Yet, as stated by EPA, generation of H_2SO_4 occurs from the oxidation of sulfur in the fuel (AAQIR at 29), and thus facilities that burn coal with higher sulfur content will emit higher levels of H_2SO_4. The Thoroughbred Generation Station will burn coal with much higher sulfur content (4.24%) than the New Mexico coal to be utilized at DREF with a sulfur content of 0.82%. One would thus expect the uncontrolled H_2SO_4 emissions at the Thoroughbred Generating Station to be much higher than at DREF. Consequently, Sithe's comparison of its proposed H_2SO_4 emission limit to the H_2SO_4 emission limit that applies to the Thoroughbred Generating Station based on its planned use of a WESP does not sufficiently show that the proposed H_2SO_4 limit reflects the maximum degree of H_2SO_4 reduction that can be achieved at DREF.

Further, information submitted with the DREF permit application from EPA's RACT/BACT/LAER Clearinghouse shows that there are two other facilities with lower H_2SO_4 limits: Unit 8 at the W.A. Parrish power plant which is subject to a 0.00150 lb/MMBtu H_2SO_4

[115] See October 15, 2004 Approval Order for New Unit 3 at the Intermountain Power Generating Station, Condition 12, at 9 (**Attachment 35**).
[116] See October 12, 2004 Approval Order for Sevier Power Company, Condition 12, at 10 (**Attachment 36**).
[117] See March 2, 2004 Permit to Construct for Longview Power, Conditions A.8. and A.18., at 4, 9. (**Attachment 37**).

emission limit and the AES-PRCP power plant which is subject to a 0.00240 H_2SO_4 lb/MMBtu emission limit. See Table 2-6 of Attachment 2 to the May 2004 DREF PSD Permit Application.

Thus, in summary, neither Sithe's DREF permit application or EPA's AAQIR provide adequate justification to show that the proposed H_2SO_4 limit truly reflects BACT at DREF.

5. THE PROPOSED STARTUP AND SHUTDOWN EMISSION LIMITS ARE UNJUSTIFIED AND VIOLATE CLEAN AIR ACT BACT REQUIREMENTS

EPA has proposed to allow Sithe to be exempt from continuously operating and maintaining its air pollution control equipment for controlling NO_x, SO_2, H_2SO_4, HF, or PM emissions during periods of startup and shutdown. See Condition IX.B.7. of the proposed DREF permit. EPA has also proposed separate pound per hour emission limits for NO_x, SO_2, and CO that would apply during startup and shutdown. Condition IX.N.2 of the proposed DREF permit. These conditions amount to outright exemptions from BACT requirements during startup and shutdown which are clearly not allowed under the Clean Air Act and EPA policy.

The emission limits defined as BACT may not include exemptions for excess emissions due to startup or shutdown, or malfunction or maintenance/planned outage for that matter. Emission limits defined as BACT under the PSD program are established under Title I of the Clean Air Act and are intended to be protective of ambient air standards as well as to be technology forcing. The ambient air quality standards are to be met on a continuous basis. Thus compliance with the BACT limits must also be on a continuous basis.[118]

Indeed, Section 302(k) of the Clean Air Act expressly defines the term "emission limitation" as a limitation on emissions of air pollutants "on a continuous basis." Section 169(3) of the Clean Air Act, in turn, defines BACT as an "emission limitation." Accordingly, the Clean Air Act mandates that BACT continuously limit emissions of air pollutants.

EPA's January 28, 1993 guidance memo entitled "Automatic or Blanket Exemptions for Excess Emissions During Startup, and Shutdowns Under PSD" (**Attachment 38** on the attached exhibit list) specifically disallows automatic exemptions from BACT emission limits and instead informs states to use enforcement discretion in determining whether to enforce for violations of

[118] As the EAB has recently explained, "because routine startup and shutdown of process equipment are considered part of the normal operation of a source . . . [e]xcess emissions (i.e., air emission that exceed any applicable emission limitation) that occur during these periods are generally not excused and are considered illegal." *In re Indeck-Elwood*, PSD Appeal 03-04, slip op at 72-73, (EAB, Sept. 26, 2006), 13 E.A.D. __, Thus, sources must be subject to emission limitations during startup and shutdown and such limitation must "be equivalent to BACT, and the permitting authority must provide a methodology for compliance." Id. slip op at 74. Moreover, the Board has held that even where the permitting authority can demonstrate that less stringent "secondary limits" are appropriate (which it has not done here), such limits "must be, nonetheless, justified as BACT." Id, slip op at 71 n.100 (noting that the permitting authority must determine "that compliance with the permit's BACT and other emission limits cannot be achieved during startup and shutdown *despite best efforts*" before establishing alternative limits, and even then such limits "must be . . . justified as BACT") quoting *In re Tallmadge Generating Station*, PSD Appeal No. 02-12, at 28 (EAB, May 21, 2003). Accordingly, to the extent that EPA has included exemptions in the permit for the DREF that apply during startup or shutdown, or has included alternative "secondary" limitation in the PSD permit, it has failed utterly to justify those permit conditions and therefore must either remove them or specifically justify them and provide an opportunity for public comment on such justifications.

BACT emission limits. EPA's policy also indicates that alternative emission limits for startup and shutdown "could effectively shield excess emissions arising from poor operation and maintenance or design, thus precluding attainment." EPA's January 28, 1993 guidance memo at 3. Instead, EPA policy indicates that enforcement discretion is the preferred approach for addressing the occurrence of excess emissions. EPA states:

> . . .infrequent periods of excess emissions during startup and shutdown need not be treated as violations where the source adequately shows that the excess could not have been prevented through careful planning and design and that bypassing of control equipment was unavoidable to prevent loss of life, personal injury, or severe property damage. Startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the planning, design and implementation of operating procedures for the process and control equipment. Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods.

Id. at 2.

Indeed, even Sithe indicated in its May 2004 PSD Permit Application for DREF that it did not need exemptions or alternative emission limits during startup and shutdown:

> Start up and shutdown emissions have received much attention in the permitting of combustion turbines, since those sources may exhibit higher mass emissions during start up than during maximum operation. This is generally not the case for coal-fired boilers, which exhibit peak mass emission rates at maximum firing rate. Startup and shutdown procedures for the pulverized coal-fired boilers are designed to provide for equipment protection while minimizing emissions. Initial start up duration after an outage may be dictated by the need to gradually warm up refractory materials, metal surfaces, and the 750 MW steam turbine, and this is normally accomplished with start up fuel (such as oil), auxiliary steam (to help preheat steam-side components) and low load operation. . . The maximum number of startups is anticipated to be 60 per year, an average of 30 per boiler (4 cold, 10 warm and 16 hot). Startup and shutdown operations do not result in any excess daily or annual emissions compared to normal continuous operation. Thus, Desert Rock Energy Facility does not request any additional limits (beyond maximum allowable mass emission limits) to govern operations during start up and shutdown.

May 2004 DREF PSD Permit Application at 5-1.

Not only did Sithe not request or provide any justification for exemptions from BACT limits or for alternative emission limits during startup and shutdown, but EPA did not provide any discussion or justification in its AAQIR for its proposed startup/shutdown exemptions and emission limits in the DREF proposed permit.[119]

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[119] Any decisions regarding allowances for facility performance during startup or shutdown that do not reflect continuous compliance with BACT limitations must be reflected in an "on-the-record determination." *See Indeck-*

The proposed startup/shutdown limits do not by any measure meet BACT, especially since Condition IX.B.7. of the proposed DREF permit doesn't even require the operation of the BACT control equipment during startup or shutdown periods. The alternative startup/shutdown limit for both SO_2 and NO_x is 797 lb/hr per boiler, which equates to, at the very best, SO_2 and NO_x emission rates of 0.12 lb/MMBtu. However, this is assuming that each unit is operating at the maximum hourly heat input capacity of 6,800 MMBtu/hr during startup and shutdown, which is not generally the case. Instead the units would be operating at lower heat input capacities and thus the equivalent lb/MMBtu emission rate would be much higher than 0.12 lb/MMBtu. Clearly, the alternative provisions for startup and shutdown do not meet BACT.

Further, EPA did not even require Sithe to model the DREF at the significantly higher startup and shutdown limits for SO_2, NO_x and CO allowed in Condition IX.N.2. of the proposed permit nor did EPA require PM, H_2SO_4, and HF emissions be modeled at uncontrolled emission rates, which is essentially what is allowed pursuant to Condition IX.B.7. of the proposed DREF permit. Yet, as Sithe and EPA have indicated, there could be 60 startups and shutdowns at DREF during each year! In addition, EPA's proposed definitions of startup and shutdown in Conditions IX.N.2. and 3. of the proposed DREF permit are quite vague and unenforceable, and could allow such periods of excess emissions to go on for long periods of time. For example, "startup" is defined in the proposed permit as:

> the period beginning with ignition and lasting until the equipment has reached a continuous operating level and operating permit limits.

Condition IX.N.2. of the proposed DREF permit.

It is not clear at all what is meant by "the equipment has reached a continuous operating level and operating permit limits." What equipment? All equipment associated with the facility? And what is meant by "operating permit limits?" It seems this could mean the facility can be considered in startup mode until it complies with its operating permit limits. The definition of "shutdown" is similarly vague:

> Shutdown shall be defined as the period beginning with the lowering of equipment from base load and lasting until fuel is no longer added to the boiler and combustion has ceased.

Condition IX.N.3. of the proposed DREF permit.

It is not clear what is "base load" and what exactly is the "lowering of equipment from base load."

Elwood, slip op at 69 (requiring an on-the-record determination of the infeasibility of measuring emissions in order to justify alternative "work practice" standards during startup and shutdown).

Thus, based on the wording of these exemptions and defined terms, not only are the requirements of the permit effectively unenforceable, but it seems probable that excess emissions could occur for periods of 24 hours or longer and still be considered to occur during startup or shutdown. If one boiler was in startup mode for one day, that could equate to 19,128 lb/day (or 9.5 tons per day) of each SO_2 and NO_x emissions that would be allowed to be emitted to the air. Filterable particulate emissions could be emitted at uncontrolled emission rates, which could equal 6,800 lb/hr or a total of 163,200 lb/day (81.6 tons per day).[120]

The levels that Sithe modeled for the NAAQS, Class I and II increment, and visibility analyses were much lower than what is allowed to occur during startup and shutdown under the proposed permit. (See Table 2-2 of DREF's Class II Modeling Update (June 2006) at 2-6 and Table 2-2 of DREF's Class I Modeling Update (January 2006) at 2-7). Thus, EPA cannot rely on the modeling analyses performed for the DREF permit to verify that, during startup or shutdown, the DREF facility will not cause or contribute to violations of the NAAQS or PSD increments, or that it won't cause or contribute to adverse impacts on visibility or other air quality related values at affected Class I areas. Not only would the DREF modeled ambient impacts increase as a result of EPA's proposed exemption and alternative SO_2, NO_x and CO emission limits for startup and shutdown, but also DREF's area of significant impact (both for Class II areas and for Class I areas) would increase and that increased significant impact area would likely cover more existing air pollution sources that should have been included in a cumulative analysis as well as require cumulative increment and visibility analyses in additional Class I areas than those already modeled by Sithe.

In short, if EPA persists in retaining Conditions IX.B.7. and IX.B.2. in the final DREF permit (or in including another exemptions or alternative emission limits for startup and shutdown emissions), <u>all</u> of the modeling analyses for DREF would have to be completely redone to verify that the DREF would not cause or contribute to violations of ambient air standards or adversely impact air quality related values during periods of startup and shutdown. Moreover, because of the vagueness of the startup and shutdown provisions, the permit terms are effectively unenforceable and therefore invalid.

Thus, for all of the above reasons, EPA must remove the exemptions and alternative emission limits for startup and shutdown currently in Conditions IX.B.7. and IX.B.2. of the draft DREF permit. There is no legal basis in the Clean Air Act and no technical justification in the permit record for including these conditions in the DREF permit.

6. EPA FAILED TO PROPOSE ANY EMISSION LIMITS FOR MERCURY

The proposed permit for Desert Rock does not include any proposed emission limits for mercury. Although Sithe committed to install mercury specific control technology "if required" and achieve 80% mercury reductions (see May 2004 DREF PSD Permit Application at 2-10, 2-11, and 4-26), EPA is silent on this significant issue in both the proposed permit and in its AAQIR.

[120] The level of uncontrolled PM emissions was backcalculated assuming the 0.010 lb/MMBtu emission limit reflects at least 99% control.

It is important to note that the highest nationwide atmospheric mercury concentration in 2001 was measured in New Mexico.[121] As EPA is aware, recent studies sponsored by the Agency demonstrate that up to 70 percent of local deposition of mercury from power plants and industrial sources can be linked to local sources during wet deposition events.[122] While DREF is located in a generally dry region, episodes of wet deposition do occur with some frequency, with the result that there are already high levels of mercury in water bodies nearby the proposed Desert Rock power plant. Specifically, fish consumption advisories due to mercury contamination have been issued for the nearby San Juan River, the Lake Farmington Reservoir and the Navajo Reservoir, as well as for Narraguinnep and McPhee Reservoirs in southwest Colorado. [123]

Thus, mercury controls and emissions from the Desert Rock power plant are an extremely important public and environmental health issue, that also implicate the trust relationship between EPA and the Navajo Nation and that must be addressed by EPA before issuing a permit authorizing construction of the Desert Rock power plant.

Given the high levels of local mercury contamination already present, it defies logic for EPA to ignore the opportunity to require state-of-the-art mercury controls at this plant, which can achieve up to 90 percent removal rates. ADA-ES systems as early as 2002 were reporting up to 90 percent mercury removal.[124]

At a minimum, EPA's Clean Air Mercury Rule requires that states submit plans to control mercury from electrical generating units no later than November 17, 2006. 40 C.F.R. §60.24(h)(2). EPA's regulation further provides that the Navajo Nation may submit a plan if approved for treatment as a state under 40 C.F.R. Part 49. 40 C.F.R. §60.24(h)(1). Each "State Plan" is to contain:

> emission standards and compliance schedules and demonstrate that they will result in compliance with the State's annual electrical generating unit (EGU) mercury (Hg) budget for the appropriate periods.

40 C.F.R. §60.24(h)(3).

The Annual EGU Hg Budget for the Navajo Nation Indian Country is 0.601 tons between 2010 and 2017, and 0.237 tons beginning in 2018 and thereafter. *Id.*

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[121] National Atmospheric Deposition Program (NRSP-3)/Mercury Deposition Network. (2003). NADP Program Office, Illinois State Water Survey, 2204 Griffith Drive, Champaign, IL 61820. Available at http://nadp.sws.uiuc.edu/mdn/

[122] Gerald Keeler, Matthew Landis, *et al*., Sources of Mercury Wet Deposition in Eastern Ohio, USA, 40 Envtl. Sci. & Tech. 5874-5881 (Sept. 2006) (**Attachment 39**).

[123] EPA 2002 and data from National Listing of Fish and Wildlife Advisories. Available at http://map1.epa.gov/

[124] Michael Durham, ADA Environmental Solutions, Testimony before the U.S. Senate Committee on Environmental & Public Works (January 29, 2002), **Attachment 40;** see also Michael Durham, PhD, MBA, Institute of Clean Air Companies "Availability of Mercury Measurement and Control Technology" (June 1, 2006), **Attachment 63**.

The 1999 mercury emissions of the Navajo and Four Corners power plants already exceed this cap. Specifically, the Navajo power plant emitted 0.1517 tons of mercury in 1999 and the Four Corners power plant emitted 0.5258 tons of mercury in 1999, which combined total 0.6775 tons. See EPA's Emissions of Mercury by Plant – 1999, listed as **Attachment 41** on the attached exhibit list).

Sithe indicated that it would take three years to complete construction of the first Desert Rock unit, with the second unit coming on line approximately one year later. May 2004 DREF PSD Permit Application at 1-1. Thus, the DREF will be operating and emitting mercury emissions by the time the mercury cap for the Navajo Nation Indian Country applies in 2010.

It must be noted that EPA incorrectly identified potential mercury emissions from Desert Rock as 0.057 tons per year (or 114 pounds per year). AAQIR at 5. However, this total of mercury emissions clearly took into account Sithe's plans, "if necessary," to control mercury emissions by 80% and meet a mercury emissions level of 8.64 x 10^{-6} lb/MWh. May 2004 DREF PSD Permit Application at 4-26 and 5-2. EPA has not proposed any level of mercury control or any mercury emission limitation for DREF so the only enforceable limitation on mercury emissions is the limit of 42 x 10^{-6} lb/MWh that applies to new EGUs burning subbituminous coal and equipped with wet scrubbers pursuant to 40 C.F.R. §60.45a(a)(2)(i). This would equate to allowable mercury emissions from DREF of 0.27741 tons per year (or 554.82 pounds per year).

Thus, adding the allowable mercury emissions from DREF with the 1999 Hg emissions from the Navajo and Four Corners power plants equals a total of 0.95491 tons of mercury that could be emitted in 2010. It is also significant to note that the Hg emissions from the Four Corners and Navajo power plants will likely increase by 2010 as these facilities move toward operating at higher capacities. In any case, it is clear that, without a plan to reduce Hg emissions from either the Navajo or Four Corners power plants (or both), the Navajo Nation will exceed its allowable Annual EGU Hg budget in 2010. The DREF facility will only exacerbate this problem.

In the absence of an approved mercury reduction plan from the Navajo Nation for these sources, it is incumbent upon EPA to ensure that this mercury cap will be complied with and, especially, to ensure that any new Hg emissions allowed to be emitted from new EGUs on the Navajo Nation lands are minimized to the greatest extent possible. In this case, Sithe has committed to install mercury controls "if necessary." In order for the Navajo Nation to comply with the applicable Annual EGU Hg Budgets for 2010 and 2018 as well as to limit the amount of mercury to be added to this already significantly contaminated part of the West, clearly it is "necessary" for EPA to require stringent mercury controls at DREF reflective of current state-of-the-art technology. EPA must not issue the permit authorizing construction of DREF without addressing this significant issue.

7. SITHE FAILED TO PROVIDE ANY ANALYSIS OF DREF'S IMPACTS ON OZONE CONCENTRATIONS IN THE REGION

The DREF will be a major source of ozone precursors. Specifically, the potential to emit volatile organic compounds (VOCs) of DREF is 166 tons per year and the potential to emit NO_x is 3,325 tons per year. AAQIR at 5. EPA has identified both of these pollutants as precursors to ozone formation. See 40 C.F.R. §52.21(b)(1)(ii) as amended on November 29, 2005 (70 Fed. Reg. 71612). Accordingly, Sithe was required to provide a demonstration that DREF would not cause or contribute to a violation of the ozone NAAQS pursuant to 40 C.F.R. §52.21(k)(1). Sithe did not provide such a demonstration. Instead, Sithe relied on the photochemical modeling study that was done by the New Mexico Environment Department (NMED) in 2004 which included new sources such as one claimed to be similar to DREF. May 2004 DREF PSD Permit Application at 6-50. Because that modeling demonstrated compliance with the 8-hour ozone NAAQS, Sithe concluded that DREF will not cause or contribute to a violation of the ozone NAAQS in the region. *Id.*

However, as discussed in comments prepared on October 5, 2006 by Khanh Tran of AMI Environmental ("October 5, 2006 Tran report" incorporated herein and attached to this comment letter) and comments prepared on October 25, 2006 by Dr. Jana Milford of Environmental Defense ("Milford Report" incorporated herein and attached to this comment letter), the ozone study prepared by the NMED is not adequate to demonstrate that DREF won't cause or contribute to a violation of the ozone NAAQS for many reasons including the following:

- The NMED study relied on incorrect NO_x, VOC and SO2 emissions for DREF. For example, the NO_x emissions modeled for DREF were less than half of DREF's allowable NO_x emissions as report in the May 2004 DREF PSD Permit Application. See October 5, 2006 Tran report at 9-10.

- The DREF project location and stack parameters are different than what was modeled for Desert Rock in the NMED study. *Id.* at 10.

- These discrepancies in modeled emissions, location, and stack parameters for the DREF "raise serious doubts about the validity of the modeling results of the NMED modeling study." *Id.* at 11.

- The portion of NMED's study that included the emissions of a power plant similar to DREF was limited to a 4-day episode, which is not a long enough period to represent DREF's impacts on ozone in the region. See Milford report at 5.

- At best, only two of the four days evaluated in the NMED study included meteorological conditions that may have transported DREF's emissions to the impact area of greatest concern. *Id.* at 6.

- Model performance was inadequate on one of the 4 days modeled, with predicted concentrations much lower than actual ozone concentrations. *Id.*

Even if the NMED modeling results were considered acceptable for assessing DREF's impacts on ozone concentrations, the model results indicate that the ozone precursor emissions from the power plants modeled would have a significant impact on ozone concentrations in the region especially when compared to the impacts of other sources modeled. And this determination is based on modeled NO_x emissions for the "Desert Rock" power plant that were less than half of the allowable NO_x emissions that could be emitted from DREF. *Id.* at 7.

In addition, it is important to note that to comply with the mandates of the prevention of significant deterioration program of the Clean Air Act, DREF's impact on ozone concentrations "must be evaluated for their impact in degrading air quality and harming human health and the environment, not just whether or not they push the Farmington area over the existing NAAQS.[125]" *Id.* at 11. As discussed in the Milford Report, the mandates of the PSD program are:

(1) to protect public health and welfare from any actual or potential adverse effect which in the Administrator's judgment may reasonably be anticipated to occur, … notwithstanding attainment and maintenance of all national ambient air quality standards;
(2) to preserve, protect, and enhance the air quality in national parks, national wilderness areas, …;
(3) to insure that economic growth will occur in a manner consistent with the preservation of existing clean air resources;
(4) to assure that emissions from any source in any State will not interfere with any portion of the applicable implementation plan to prevent significant deterioration for any other State; and
(5) to assure that any decision to permit increased air pollution in any area … is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decisionmaking process.[126]

Further, section 166(a) of the Clean Air Act requires EPA to promulgate additional regulations to prevent the significant deterioration of air quality which would result from hydrocarbons, carbon monoxide, photochemical oxidants [ozone], and nitrogen oxides, which regulations are to "fulfill the goals and purposes set forth in section 7401 and 7470 [160] of this title" and "provide specific measures at least as effective as the increments established in section 7473 [for particulate matter and sulfur dioxide]." EPA has never promulgated the required regulations for photochemical oxidants or ozone, but EPA is still obligated to ensure that PSD permits comply with all of the mandates of the prevention of significant deterioration program.

Considering that the Clean Air Science Advisory Committee has recommended that the current NAAQS for ozone needs to be lowered to no more than 70 parts per billion,[127] a

[125] Environmental Defense Fund v. EPA, 898 F.2d 183, 190 (D.C. Cir. 1990).
[126] 42 U.S.C. § 7470.
[127] See October 24, 2006 letter to the EPA from Dr. Rogene Henderson, Chair, Clean Air Scientific Advisory Committee with CASAC's Peer Review of the Agency's 2nd Draft Ozone Staff Paper, at 2 (**Attachment 61**).

level of ozone pollution which San Juan County has exceeded in recent years[128], it is imperative that Sithe and/or EPA provide a sufficient analysis of the DREF facility's impact on ambient ozone concentrations in the region. The DREF PSD permit application is entirely incomplete without such an analysis, and EPA would have no basis to issue a permit to DREF without this critical information on the facility's impacts on ozone air quality.

8. SITHE FAILED TO PROVIDE A DEMONSTRATION THAT DREF WON'T CAUSE OR CONTRIBUTE TO A VIOLATION OF THE $PM_{2.5}$ NAAQS

Sithe did not perform any modeling to determine DREF's impacts on fine particulate ($PM_{2.5}$) concentrations in the area. EPA failed to require any such modeling and instead stated that it was treating PM_{10} as a surrogate for $PM_{2.5}$ for the Desert Rock permit. AAQIR at 5. This is scientifically unacceptable. Sithe must be required to perform modeling to assess its impact on $PM_{2.5}$ concentrations and to ensure that it won't cause or contribute to a violation of the $PM_{2.5}$ ambient air quality standards as revised by EPA on October 17, 2006 (71 Fed.Reg. 61144). $PM_{2.5}$ is a significant public health concern that must not be ignored.

9. DREF'S NEAR-FIELD MODELING ANALYSES FOR THE CLASS II PSD INCREMENT AND NAAQS SHOULD NOT HAVE UTILIZED CALPUFF

As discussed in the October 5, 2006 Tran report (at 7), the near-field analysis utilized the Calpuff model which is inappropriate for estimating near-field, short-range impacts of DREF. The use of AERMOD is instead recommended to insure that air quality impacts are not underpredicted. *Id.* This is especially important since the 24-hour PM_{10} concentration predicted to occur as a result of DREF is only 8% below the PM_{10} Class II PSD increment. *Id.*, see also Table 4-6 of DREF Class II Modeling Update (June 2006), at 4-8. Sithe must be required to use the model that will most accurately predict its near-field impacts.

10. THE DREF NAAQS MODELING IS INADEQUATE

<u>The SO_2 NAAQS Modeling is Flawed Because Sithe Failed to Model Allowable Emission Rates of Nearby Sources</u>

In addition to the issue discussed above of failing to use the appropriate model to estimate near-field impacts of DREF, there are numerous other reasons why the NAAQS modeling is inadequate. EPA cannot rely on the near-field modeling as adequately demonstrating that DREF won't cause or contribute to a violation of the NAAQS.

First, as discussed earlier in this comment letter, no modeling was done of the maximum emission rates allowed by the startup/shutdown exemptions and alternative emission limits of Conditions IX.B.7. and IX.B.2. of the proposed DREF permit.

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[128] See http://www.nmenv.state.nm.us/aqb/projects/Ozone.html.

Second, the DREF cumulative NAAQS modeling analysis failed to model all sources at allowable emission rates. As required by EPA's Guideline on Air Quality Models, nearby sources are to be modeled at allowable emission rates. See 40 C.F.R. Part 51, Appendix W, Table 9-2 and Section 9.1.2.i. DREF's modeling is required to comply with EPA's modeling guidelines pursuant to 40 C.F.R. §52.21(l). This major flaw is particularly apparent for the SO_2 NAAQS analysis. The sources included in the NAAQS modeling for SO_2 are listed in Appendix A to the DREF Class II Area Modeling Update (June 2006). The Four Corners and San Juan power plants are by far the largest SO_2 sources included in the cumulative SO_2 NAAQS analysis. A review of what was modeled for those sources compared to what those sources are allowed to emit shows that Sithe greatly underestimated cumulative SO_2 impacts in its NAAQS analysis. Table 6 below identifies the SO_2 emission rates modeled for these two power plants in the SO_2 NAAQS analysis.

Table 6. SO_2 Emission Rates Modeled in NAAQS Analysis for Existing Power Plants, from Appendix A of June 2006 DREF Class II Area Modeling Update

Power Plant Unit Modeled	**SO_2 Emission Rate Modeled, lb/hr**
San Juan Unit 1	1,608.60
San Juan Unit 2	1,600.30
San Juan Units 3 and 4[129]	4,997.40
Four Corners Units 1 and 2[130]	1,496.35
Four Corners Unit 3	873.52
Four Corners Unit 4	2,169.86
Four Corners Unit 5	1,496.35

Thus, the total modeled for the San Juan power plant was 8,206.3 lb/hr and the total modeled for the Four Corners power plant was 6,036.08 lb/hr. It appears that these emission rates were modeled for all averaging times in the SO_2 NAAQS analysis. However, the emission rates modeled fall far short of these power plants' allowable emissions. The 3-hour allowable SO_2 plantwide emission limit at San Juan is 13,000 lb/hr.[131] Each unit is also subject to a 1.2 lb/MMBtu SO_2 limit on a 3-hour average basis.[132] The emission rates modeled for San Juan were one-third lower than what the facility is allowed to emit on a 3-hour average basis. The short term average allowable SO_2 emission rate should have been modeled in both the 3-hr and 24-hr SO_2 NAAQS cumulative analyses for DREF.

A review of the Title V permit for the Four Corners power plant shows that this facility is only subject to annual ton per year SO_2 limits under the acid rain program.[133] Although EPA has recently proposed a Federal Implementation Plan (FIP) for the Four Corners power plant that includes a 3-hour average plantwide cap of 17,900 lb/hr (71 Fed.Reg.

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[129] These two units appear to have been combined in the DREF modeling.
[130] These two units also appear to have been combined in the DREF modeling.
[131] See August 7, 1998 Title V Permit for the San Juan Generating Station at 12 (**Attachment 42**).
[132] *Id.*
[133] See 6/12/01 Title V Permit to Operate for Four Corners Steam Electric Station, Condition II.A.3.a. (**Attachment 43**), downloaded from EPA Region 9's permit tracking website.

53636, September 12, 2006), this FIP has not been promulgated. Because there are no currently enforceable limitations on short term SO_2 emission rates at Four Corners power plant, these units must be modeled at uncontrolled SO_2 emission rates in the NAAQS analyses as what is currently allowed at these units. The plantwide uncontrolled SO_2 emissions at Four Corners would be roughly 33,000 lb/hr of SO_2.[134] Even if the 17,900 lb/hr cap was an enforceable emission limit, Sithe modeled total SO_2 emissions that were about one-third of this proposed allowable SO_2 emissions limit.

Thus, the DREF cumulative SO_2 NAAQS modeled is significantly flawed and EPA cannot proceed to issue a permit to DREF because it is not clear whether the facility will cause or contribute to a violation of the SO_2 NAAQS. Sithe must be required to model the allowable SO_2 emissions of all sources including minor sources and sources on tribal lands in addition to the major sources of SO_2 in the area.

The SO_2 NAAQS Modeling Also Relied on Incorrect Background Concentrations

According to the June 2006 DREF Class II Area Modeling Update, a value of 6.2 μgm^3 was considered as the background concentration for the 3-hr, 24-hr, and annual SO_2 NAAQS analyses. June 2006 DREF Class II Area Modeling Update at 4-20. However, this background concentration is much lower than what Sithe previously reported were the background concentrations in the May 2004 DREF PSD Permit Application (at 6-7). Specifically, the SO_2 regional background concentrations used in the May 2004 NAAQS analyses for DREF were 68.1 μgm^3 for the 3-hour average SO_2 NAAQS and 21.0μgm^3 for the 24-hour average SO_2 NAAQS. (May 2004 DREF PSD Permit Application at 6-7 and 6-27). Thus, not only was the cumulative DREF SO_2 NAAQS analysis not based on the allowable emission rates of the Four Corners and San Juan power plants, and also probably other nearby sources, but it also did not add in the appropriate background concentrations.

With all of these errors, the DREF cumulative modeling analyses significantly underestimated impacts on the SO_2 NAAQS and thus the DREF SO_2 modeling cannot be relied upon to verify whether DREF will cause or contribute to a violation of the SO_2 NAAQS. The inappropriate use of the Calpuff model for the near-field impacts as described in comment 9 above also likely exacerbates the deficiencies in the SO_2 NAAQS analysis.

The PM_{10} NAAQS Modeling Failed to Model the Allowable Emission Rates of All Nearby Sources, including the Four Corners Power Plant

As discussed above, Sithe failed to model all nearby sources in the SO_2 NAAQS analysis at allowable emission rates. This flaw likely persists for the sources modeled in the cumulative PM_{10} NAAQS analysis. EPA must review the allowable emissions of all

[134] The uncontrolled SO2 emissions were estimated based on reported heat input capacities of each unit and uncontrolled SO2 emission rate of 1.68 that was backcalculated out of the information in EPA's June 10, 1981 Federal Register notice (i.e., that Four Corners would meet a plantwide emission rate of 0.47 lb/MMBtu which was to reflect 72% control). See 46 Fed.Reg.30653-4, June 10, 1981.

sources included in the cumulative NAAQS analyses and ensure that such sources were modeled at allowable emission rates as required by EPA modeling regulations.

While it appears that the San Juan power plant was modeled at its allowable PM emission rates, the PM_{10} NAAQS modeling for DREF as updated failed to include any PM emissions from the Four Corners power plant. Specifically, a review of all of the sources included in the cumulative PM_{10} NAAQS assessment shows that Four Corners power plant was not one of those sources. Appendix A to the DREF Class II Area Modeling Update (June 2006). Interestingly, the Four Corners power plant was included in the PM_{10} NAAQS modeling done for the May 2004 DREF PSD Permit Application. (See May 2004 DREF PSD Permit Application at 6-24). This is a major oversight in the cumulative PM_{10} NAAQS modeling. EPA has recently proposed a Federal Implementation Plan (FIP) for the Four Corners power plant that includes PM emission limits of 0.05 lb/MMBtu (71 Fed.Reg. 53636, September 12, 2006), but this FIP has not yet been promulgated. As discussed above, because there are no currently enforceable limitations on short term PM_{10} emission rates at Four Corners power plant, these units must be modeled at uncontrolled PM_{10} emission rates in the NAAQS analyses as that is what these units are allowed to emit. It is also important to note that, if these units were subject to enforceable 0.05 lb/MMBtu PM emission limits as proposed by EPA, then what was modeled for these units as identified in the May 2004 DREF PSD Permit Application was only half as much as what would be the facility's allowable PM emissions if EPA promulgates the FIP as proposed.

Thus, the DREF cumulative PM_{10} NAAQS modeling is significantly flawed and EPA cannot proceed to issue a permit to DREF because it is not clear whether the facility will cause or contribute to a violation of the PM_{10} NAAQS. Sithe must be required to model the allowable SO_2 emissions of all sources including minor sources and sources on tribal lands in addition to the major sources of SO_2 in the area.

The PM_{10} NAAQS Modeling Also Relied on Incorrect Background Concentrations

According to the June 2006 DREF Class II Area Modeling Update, a value of 20 μgm^3 was considered as the background concentration for the 24-hr and annual PM_{10} NAAQS analyses. June 2006 DREF Class II Area Modeling Update at 4-20. However, this background concentration is much lower than what Sithe previously reported was the 24-hour average PM_{10} background concentrations in the May 2004 DREF PSD Permit Application (at 6-7). Specifically, the PM_{10} regional background concentration used in the May 2004 NAAQS analyses for DREF was 38 μgm^3 for the 24-hour average PM_{10} NAAQS. (A background value of 17.0μgm^3 was used for the annual average PM_{10} NAAQS analysis in the May 2004 DREF PSD Permit Application, which is somewhat lower than what was considered as background for the June 2006 Class II Area Modeling Update.) May 2004 DREF PSD Permit Application at 6-7 and 6-27. Thus, in addition to the major flaws with the PM_{10} NAAQS inventory modeled, the 24-hour PM_{10} NAAQS analysis as updated did not add in the appropriate 24-hour average PM_{10} background concentrations.

With these major errors, the DREF cumulative modeling analyses significantly underestimated impacts on the PM_{10} NAAQS and thus the DREF PM_{10} modeling cannot be relied upon to verify whether DREF will cause or contribute to a violation of the PM_{10} NAAQS. The inappropriate use of the Calpuff model for the near-field impacts as described in comment 9 above also likely exacerbates the deficiencies in the PM_{10} NAAQS analysis.

11. THE DREF NO2 MODELING UNDERESTIMATED AMBIENT IMPACTS

The DREF NO_2 modeling is flawed for numerous reasons. First, the national default ratio of 0.75 for NO_2/NO_x was used. June 2006 DREF Class II Area Modeling Update at 4-6. However, use of this conversion ratio is not appropriate unless justified, and especially when determining whether "significant" NO_2 impacts would occur as a result of DREF. As discussed in EPA's Guidelines for Air Quality Models, 100% NO_x to NO_2 conversion should be assumed – especially for an initial analysis to determine a facility's significant impact area. See 40 C.F.R. Part 51, Appendix S, Section 6.2.4.b. In addition, the modeling guideline cautions against using the national 0.75 NO_2/NO_x ratio in assessing long range transport impacts, and states that any ratio "can underestimate long range transport NO_2 impacts." *Id.*, Section 6.2.4.c. Thus, for determining significance, Sithe should have modeled 100% of NO_x emissions as NO_2.

Second, Sithe did not model all NO_x emissions associated with the DREF facility in its NO_2 impacts analysis. Specifically, Sithe did not model any tailpipe NO_x emissions expected from the vehicular traffic associated with the DREF. According to the June 2006 Class II Area Modeling Update (at page 2-13), 15,017 vehicle miles traveled (VMT) per year are expected from vehicular travel associated with the transport of limestone, ash, gypsum, fuel oil, hydrated lime/activated carbon, and anhydrous ammonia." *Id.* at 2-8. Further, Sithe did not include any NO_x emissions associated with production of the coal supply for DREF from the nearby BHP Billiton coal mine. Sithe must include all NO_x emissions associated with DREF in determining whether the facility will have a significant impact on NO_2 concentrations nearby or in Class I areas in the region.

Third, as discussed in comment 9 above, it was not appropriate to use Calpuff for the near-field modeling.

All of these deficiencies could have resulted in an underestimate of NO_2 impacts expected from the DREF. Further, DREF could have been improperly exempted from a cumulative NO_2 NAAQS analysis. As discussed in further detail in the next comment, this region is experiencing, and will continue to experience, a surge in NO_x emissions associated with gas and coalbed methane development. This is on top of the 68,500 tons per year of NO_x emitted by the Four Corners and San Juan power plants (based on 2005 data)[135]. Thus, it is imperative that EPA require Sithe to properly and conservatively model the ambient NO_2 impacts that could occur from DREF, and to require cumulative NO_2 NAAQS and PSD increment analyses based on the results. Without a revised NO_2 analysis, EPA cannot justify a determination that the DREF facility won't cause or contribute to a violation of the NO_2 NAAQS or Class I or II NO_2 PSD increment.

12. SITHE MUST CONDUCT A CUMULATIVE PSD NO_2 INCREMENT ANALYSES

No cumulative Class II NO_2 PSD increment analysis was done for DREF because the modeling of DREF sources did not predict NO_2 concentrations above modeling significance levels. See June 2006 Class II Area Update at 4-6, 4-14. However, there is a substantial body of information to indicate that the NO_2 Class II increments will soon be, or are already being, violated in northwestern New Mexico and southwestern Colorado.

The fundamental NO_2 modeling requirement for EPA and the applicant in this permit review process is to comply with Clean Air Act section 165(6), which requires that a major emitting facility may not be constructed unless "there has been an analysis of any air quality impacts projected for the area as a result of growth associated with such facility." 40 CFR § 52.21(k) makes clear this requirement entails a demonstration that the proposed source would not cause or contribute to air pollution in violation of: "(1) any national ambient air quality standard in any air quality control region; or (2) any applicable maximum allowable increase over the baseline concentration in any area." EPA regulations implementing section 165(6) contain no *de minimis* exception to requirements for a cumulative modeling analysis. As the Code of Federal Regulations clearly states, the monitoring significance levels cited in Sithe's June 2006 Class II Area Update only provide an exemption from "the requirements of paragraph (m) of this section, with respect to monitoring…" 40 CFR § 52.21(i)(5)(i). EPA's October 1990 Draft New Source Review Workshop Manual suggests a full modeling impact analysis is not required if a preliminary analysis predicts maximum NOx concentrations in Class II areas of 1 $\mu g\ m^{-3}$, annual average. NSR Manual at C.28. However, the guidance provided in the NSR Manual does not modify EPA's legal obligation to ensure compliance with the Clean Air Act and the implementing regulations. As the preface to the NSR Manual states "[this document] is not intended to be an official statement of policy and standards and does not establish binding regulatory requirements; such requirements are contained in the statute, regulations and approved state implementation plans." EPA cannot blindly follow the NSR Manual without consideration of the circumstances attending a particular permit application. The question of whether DREF would "cause or contribute" to a violation of the NO_2 increment clearly depends on whether the increment is already being approached or exceeded in the area affected by the proposed facility. A contribution of 1 $\mu g\ m^{-3}$ or less might rationally be disregarded in a setting where the full 25 $\mu g\ m^{-3}$ annual average Class II increment remains available. But where evidence exists to suggest the increment is nearly exhausted or has already been exhausted, EPA cannot rationally dismiss a contribution of up to 1 $\mu g\ m^{-3}$ as "insignificant" without

[135] Annual NOx emissions data obtained from EPA's Clean Air Markets Database.

requiring further analysis. EPA's August 7, 1980 rulemaking on its PSD regulations clearly recognizes this point, stating that the use of ambient significance levels is not always appropriate to exempt a source from a cumulative impacts analysis, especially when "existing air quality is poor or adverse impacts to a Class I area are in question." (45 Fed.Reg. 52678, August 7, 1980). Furthermore, EPA's longstanding contemporaneous interpretation of the statutory and regulatory provisions for the PSD increments clearly mandate that, in an area with existing PSD increment violations, the violations "must be entirely corrected before PSD sources which affect the area can be approved." (See 45 Fed.Reg. 52678, August 7, 1980). There is a strong likelihood of NO_2 increment violations in this area that cannot be ignored by EPA.

Oil, gas and coal bed methane energy resources are being extensively developed in northwestern New Mexico and southwestern Colorado, and substantial increases in the amount and intensity of this development are expected to occur over the next twenty years or more. There are numerous sources of NO_x emissions associated with this development including drill rig engines, wellhead compressor engines, centralized compressor stations, gas processing plants, glycol dehydrators, and separators, as well as tailpipe emissions from the increased vehicular traffic needed to construct, operate and maintain each well and the associated production facilities. Currently, the San Juan Basin is already substantially developed. In the Final Environmental Impact Statement (FEIS) for Oil and Gas Development on the Southern Ute Indian Reservation (July 2002) (Southern Ute FEIS), it is stated that there are currently more than 26,000 wells in the entire San Juan Basin (Southern Ute FEIS at 1-3, excerpt listed as **Attachment 44** on the attached exhibit list). That figure was most likely based on the level of development at the time the draft EIS was prepared in early 2001. Much more development has occurred in the last 5 years.

In 1999, likely as a result of the significant increases in air emissions sources associated with energy resource development in the region, the state of Colorado Department of Public Health and Environment released a study of the consumption of the NO_2 PSD increments in southwest Colorado.[136] While the conclusions of that study were that, in general, the NO_2 increments were being met in southwest Colorado, the modeling study did find a "hot spot" of extremely high NO_2 concentrations, above the level of the Class II NO_2 PSD increment as well as the NO_2 NAAQS. Specifically, the state modeled the Williams Field PLA-9 Compressor Station, which is located about 0.6 miles from the New Mexico border, and the predicted NO_2 concentration assuming 75% conversion of NO_x to NO_2 was 461 $\mu g/m^3$. See listing as **Attachment 45** at 73 on the attached exhibit list. This source is located in "Indian country" and thus EPA Region VIII is the permitting authority. It is not clear whether these issues have been resolved by the region.

More recent modeling performed for the Williams Field Services Company PLA-9 source in conjunction with a permit modification showed that, after several model "refinements," 19 $\mu g/m^3$ of the total Class II NO_2 increment of 25 $\mu g/m^3$ had been

[136] Periodic Assessment of Nitrogen Dioxide PSD Increment Consumption in Southwest Colorado, Phase I, October 29, 1999 (**Attachment 45**), available at http://apcd.state.co.us/permits/psdinc/.

consumed by this and other nearby contributing sources. See Air Quality Modeling Report, Nitrogen Dioxide PSD Increment Consumption in Class II Areas Surrounding PLA-9 Central Delivery Point, prepared by Cirrus Consulting, LLC, April 2001, listed as **Attachment 46** on the attached exhibit list. This modeling exercise was based on only one year of meteorological data. *Id.* at 3-4. Although showing compliance, these model results indicate there is not much room left for additional growth in NO_x emissions in this area before the Class II NO_2 increment will be violated.

Several additional air quality analyses have been conducted for the region in recent years for the issuance of several environmental planning documents to authorize increased rates of development of oil, gas, coal bed methane and other energy resources. These include the Southern Ute FEIS that was issued in July 2002, the Farmington Resource Management Plan and FEIS (Farmington RMP/FEIS) issued in March 2003, and the Northern San Juan Basin Coal Bed Methane Project FEIS (NSJB FEIS) which was made available for public review in July 2006 although no Record of Decision has been issued yet. In both the Southern Ute FEIS and the Farmington EIS, projected increases in NO_x emissions from energy development were predicted to cause NO_2 concentrations in excess of the NO_2 PSD increments.

Specifically, modeling performed for the Southern Ute FEIS predicted annual average NO_2 concentrations ranging from 31.2 $\mu g/m^3$ to 39.8 $\mu g/m^3$. See "Responses to Comment 'O' from Mark McMillan, State of Colorado, Air Pollution Control Division," excerpt from Section 5.9 of Volume 2 of the Southern Ute FEIS (July 2002) listed as **Attachment 44** on the attached exhibit list. It is important to note that most likely all of the NO_x emissions modeled in the Southern Ute air quality analysis were increment consuming emissions, since any increase in emissions after the NO_2 minor source baseline date (which was set for the entire state of Colorado on March 30, 1989) consumes the available increment.

Air quality modeling performed for the Farmington RMP/FEIS also predicted NO_2 concentrations in excess of the NO_2 Class II increments. The NO_2 minor source baseline date in northwestern New Mexico was set on June 6, 1989, and thus all of the sources modeled would be increment-consuming. The Farmington analysis was based on the modeling of an "emissions module" of 4 sections (i.e., a 4 square mile area) of 32 wells that was considered to be high density well development, and these sources were modeled as if in flat terrain. Farmington Proposed RMP/FEIS (March 2003) at 4-60 – 4-61 (see listing as **Attachment 47** on the attached exhibit list). It is important to note that this was a very small subset of the 9,942 new wells that would be allowed in the Farmington planning area. Farmington Proposed RMP/FEIS (March 2003) at 2-238(**Attachment 47**). The results of modeling this small subset of sources predicted a maximum annual average NO_2 concentration of 33 $\mu g/m^3$. Farmington Proposed RMP/FEIS (March 2003) at 4-63(**Attachment 47**). The Farmington RMP/FEIS does not include a cumulative assessment of increment consumption by existing sources, but the BLM admitted that "[t]here are several localized areas within the planning area where the available Class II increment is nearly exhausted." *Id.* The air quality modeling done for this EIS had some significant deficiencies and likely underestimated NO_2 impacts. See, e.g., May 5, 2003 Protest of the Farmington RMP/FEIS Submitted to the BLM by San Juan Citizens Alliance et al. (see listing as **Attachment 48** on the attached exhibit list).

Air quality modeling performed for the NSJB CBM FEIS also predicted NO_2 concentrations in excess of the Class II NO_2 PSD increments. Specifically, the predicted maximum NO_2 concentration just from the NSJB CBM Project sources was 24.8 µg/m^3. See June 2004 Draft Environmental Impact Statement Northern San Juan Basin Coal Bed Methane Project Air Quality Impact Assessment Technical Support Document, prepared by RTP Environmental (see listing as **Attachment 49** on the attached exhibit list), at 52. Further, the cumulative NO_2 analysis prepared for the NSJB CBM Project EIS just considering NSJB CBM sources and other existing and reasonably foreseeable sources predicted a combined total maximum NO_2 concentration of 29.3 µg/m^3. *Id.* It must be noted that the predicted NO_2 impacts of other existing and reasonably foreseeable sources reported in the NSJB CBM Technical Support Document only reflected the concentration predicted at the receptors with maximum concentration due to the NSJB CBM Project alone. *Id.* at footnote (1). In other words, there were likely higher overall peak concentrations modeled when existing and reasonably foreseeable sources were added to the mix (especially due to the growth in gas development allowed under the Farmington RMP), but those predicted concentrations were not reported as the NSJB CBM modeling was focused primarily on evaluating maximum impacts from NSJB CBM sources.

All of these analyses indicate that the NO_2 Class II increments in northwestern New Mexico and southwestern Colorado will likely be violated in the near future, if the increments are not already being violated in parts of the region due to NO_x emissions sources associated with the intense levels of energy development in the region. And, with the exception of the Colorado NO_2 increment assessment completed in 1999, these analyses prepared under NEPA did not evaluate all NO_2 increment-consuming emissions from stationary sources or from mobile and area source growth in the region.

Although the DREF's modeled NO_2 impacts were less than the "significant impact level" contained in the Draft New Source Review Workshop Manual (a modeling result for which we question its accuracy as discussed in comment 11 above), Sithe should be required to conduct a cumulative NO_2 increment analysis considering all of the increment-consuming NO_x emission sources in the region for numerous reasons. In this case, the existing air quality in the region is either violating or close to violating the Class II NO_2 PSD increments, or the increments will be violated in the near future. In addition, adverse NO_2 impacts at Mesa Verde National Park *are* in question as a result of existing and future growth in NOx emissions in the region. Indeed, the Colorado NO_2 increment study includes the results of model runs with ISCT3 that indicated a potential violation of the NO_2 increment, and that study only included emissions that existed as of 1999. See Attachment 45 at 15.

Significantly, none of the increment consumption analyses prepared for the energy development projects in the region included the emissions of the DREF. While a NO_2 increment analysis *may* be done for the DREF EIS that is forthcoming, EPA Region IX is not coordinating issuance of its construction permit for DREF with that EIS and may in fact issue the permit before the DREF

EIS even comes out. Specifically, EPA's October 20, 2006 letter to the San Juan Citizens Alliance states in part “"when the draft EIS for the Desert Rock Energy Facility is released, EPA will consider any requests to reopen the public comment period *if we have not yet issued our Response to Comments and reached a final PSD permit decision*." EPA's October 20, 2006 letter at 1, emphasis added. Yet, information on the status of NO_2 increment consumption in the area affected by the DREF is of critical importance to the PSD program in the region. And, even though a NEPA analysis should evaluate whether a proposed action will comply with all Clean Air Act standards, including a review of cumulative impacts, neither the BLM or the BIA have conducted a proper cumulative NO_2 increment analysis (considering all increment consuming emissions) as part of any EIS for the region. Indeed, the BLM consistently states that the responsibility for a complete PSD increment analysis lies with the permitting authority when issuing a PSD permit or with the agency responsible for implementing the PSD program in the area. See, e.g., NSJB CBM FEIS (July 2006) at 3-528 - 3-530, (Chapter 3 of this FEIS is listed as **Attachment 50** on the attached exhibit list).

For all of these reasons, EPA must not exempt DREF from a cumulative NO_2 PSD increment consumption analysis. Such a cumulative analysis must include all sources of NO_2 increment affecting emissions in the area including minor sources, tribal sources and mobile source growth. If EPA proceeds to issue the permit for DREF without such an analysis, it will be issuing the permit without any firm basis for determining that the project won't contribute to violations of the NO_2 increments in the region. Given the other air quality studies that have been done to date, EPA's action would be entirely unjustified.

13. THE CLASS I AREA MODELING METHODOLOGY IS FLAWED

As discussed in the October 5, 2006 Tran report, there are several flaws in the methodologies used in the Class I area modeling for air quality including the PSD increment assessment and the air quality related values evaluation. The following flaws are common to all of the Class I analysis:

- The meteorological data used in the air quality and visibility modeling analyses are too coarse to resolve the effects of complex terrain in the areas that could be impacted by DREF. October 5, 2006 Tran Report at 3-4. Further, the modeling used a set of meteorological data that is proprietary, namely the 2003 RUC data. Use of such proprietary data does not afford the public the opportunity to review and comment on the data. *Id.* at 12. Note that EPA also made the comment to the Desert Rock applicant and its consultant, ENSR, in a 5/14/04 email that “[a] PSD application, including all modeling inputs, is required under regulation to be public information, i.e., available for public examination.”[137]

- The National Park Service 4 kilometer meteorological data may not have been properly used in the regional haze assessment. *Id.* at 5.

[137] See May 14, 2004 email from Scott Bohning, EPA Region IX, to Gus Eghneim et al with subject “Desert Rock completeness & modeling inputs” which was included in EPA's Administrative Record for the proposed DREF permit.

- Air quality and visibility impacts may be understated because Sithe failed to include emissions from the auxiliary boilers and other low level emissions sources associated with DREF. *Id.* at 5.

These deficiencies in the Class I modeling likely resulted in an underestimate of Class I area impacts by DREF. Thus, these deficiencies must be corrected before EPA can rely on the Class I modeling in issuing a PSD permit for DREF. There are other deficiencies specific to each of the modeling analyses for visibility, regional haze and PSD increments that are discussed in detail in the next few comments.

14. SIGNIFICANT CUMULATIVE IMPACTS ON PSD INCREMENTS HAVE BEEN OVERLOOKED IN THE DREF PSD ANALYSES

Sithe only conducted cumulative PSD increment analyses for those Class I areas where the DREF facility would have an ambient impact greater than "Class I significant impact levels." As discussed in comment 19 below and in the October 5, 2006 Tran report at 13, National Park Service studies have raised serious concerns that the Calpuff modeling used in the DREF Class I analysis greatly underestimated DREF's SO_2 impacts in Grand Canyon National Park and other Class I areas in the region. Thus, Sithe's determination that DREF will have only "insignificant" SO_2 impacts at several Class I areas including Grand Canyon National Park is questionable.

Further, no federal regulation or guidance allows for a permit applicant to be exempt from the PSD requirement to show that the proposed source won't cause *or contribute* to a violation of the Class I PSD increments based on an "insignificant" ambient impact. Such an approach could result in Sithe overlooking significant PSD increment impacts in areas where DREF's impact may be insignificant, but cumulatively there are significant impacts such as violations. See October 5, 2006 Tran report at 11. Indeed, there is sufficient reason to believe that increment violations have been overlooked by Sithe in some Class I areas.

While EPA proposed use of Class I significant impact levels in July of 1996 (61 Fed.Reg. 38338, July 23, 1996), EPA never finalized promulgation of those significant impact levels. Until significant impact levels for Class I increment analyses are promulgated by EPA, *any* impact in a Class I area by DREF must warrant a cumulative PSD increment analysis.

In addition, use of Class I significant impact levels in areas where, cumulatively, there could be violations of the increment is contrary to EPA's interpretation of the law. EPA Region VIII stated in an April 12, 2002 letter to the North Dakota Department of Health that the use of significant impact levels to allow a PSD permit to be issued in the case of a Class I area showing increment violations is not consistent with the intent of the Clean Air Act's PSD program. (See Attachment to April 12, 2002 letter from EPA to North Dakota Department of Health, listed as **Attachment 51** on the attached exhibit list, at pages 5-6).

As discussed above in comment 12, there is a strong probability that the NO_2 increments in Mesa Verde National Park are violated or are close to being violated. Thus, DREF must not be exempt from a cumulative NO_2 increment analysis at this Class I area. It is imperative that EPA properly determine whether DREF will contribute to NO_2 increment violations at this Class I area.

In addition, existing violations of the Class I SO_2 increment are occurring in Capitol Reef National Park. During the permit review and proceedings for the proposed Unit 3 of the Intermountain Power Plant located in Delta, Utah, the National Park Service conducted a Class I SO_2 increment analysis and determined that **existing** sources in Utah are causing violations of the 3-hour average Class I SO_2 increment in Capitol Reef National Park. Specifically, on March 25, 2004, the National Park Service submitted a letter to the Utah Division of Air Quality that provided, among other things, the Park Service's formal findings that the 3-hour average SO_2 increment was being violated by existing sources in Utah at Capitol Reef National Park.[138] In May of 2003, the Assistant Secretary for Fish and Wildlife and Parks submitted a letter and accompanying Technical Support Document reiterated that existing sources are causing violations of the 3-hour average SO_2 increment at Capitol Reef National Park.[139] Because the SO_2 emissions from DREF will increase 3-hour average SO_2 concentrations in this Class I area, the DREF facility could contribute to SO_2 increment violations at Capitol Reef National Park. Therefore, EPA must require Sithe to conduct a cumulative 3-hour average SO_2 increment analysis at Capitol Reef National Park to determine whether DREF will contribute to existing SO_2 increment violations. Further, any such analysis must address all of the deficiencies currently existing in the DREF SO_2 increment analyses as discussed in the next comment.

Further, as discussed further below, it appears that there may be existing SO_2 increment violations at Mesa Verde National Park. EPA must therefore consider any impact by DREF on Class I increment violations at Mesa Verde National Park to be significant.

Thus, for all of the above reasons, EPA must require Sithe to provide cumulative PSD increment analyses for all pollutants and all Class I areas that will be affected by DREF.

15. THE DREF CUMULATIVE SO_2 INCREMENT ANALYSES ARE SEVERELY DEFICIENT AND CANNOT BE RELIED UPON BY EPA

The DREF cumulative SO_2 increment analyses are fatally flawed for numerous reasons as discussed in the November 9, 2006 report prepared by Vicki Stamper entitled "Review of the Class I SO_2 PSD Increment Consumption Analyses Performed for the Desert Rock Prevention of Significant Deterioration Permit" which is incorporated herein and attached to this comment letter. A Class I SO_2 increment modeling analyses prepared by Khanh Tran in which just a few of the numerous deficiencies in the modeled PSD increment inventory are corrected indicates that DREF will contribute to violations of the 3-hour and 24-hour average SO_2 increments at Mesa Verde National Park. See November 9, 2006 report entitled "Cumulative SO_2 Modeling Analyses of Desert Rock Energy Facility and Other Sources at PSD Class I Areas," by Khanh

[138] National Park Service Comments on the Intermountain Power Agency Prevention of Significant Permit Application for the Addition of Unit 3 at its Intermountain Power Plant, March 2004, attached to its March 25, 2004 letter to Rick Sprott, Utah Division of Air Quality, at 5. (**Attachment 52**).

[139] National Park Service Supplemental Technical Comments on the Intermountain Power Agency Prevention of Significant Permit Application for the Addition of Unit 3 at its Intermountain Power Plant, May 2004, attached to its May 2004 letter from the Assistant Secretary for Fish and Wildlife and Parks to Rick Sprott, Utah Division of Air Quality, at 8-9. (**Attachment 53**).

Tran of AMI Environmental, incorporated herein and attached to this letter. EPA therefore cannot issue the PSD permit to DREF as proposed pursuant to 40 C.F.R. §52.21(k)(2). Specifically, 40 C.F.R. §52.21(k)(2) mandates that Sithe must demonstrate DREF won't cause *or contribute* to a violation of any PSD increment.

The SO_2 Reductions Made at the San Juan and Four Corners Power Plants in the 1970's to early 1980's Cannot Be Used to Expand the SO_2 Increment for DREF.

Many of the deficiencies noted in the Stamper report pertain to Sithe's modeling of SO_2 emission reductions at the Four Corners power plant and at Units 1 and 2 of the San Juan power plant as expanding the available SO_2 increment. Under the PSD regulations, emission reductions that occurred after the minor source baseline date at sources which were in existence as of the minor source baseline date can expand the amount of available increment to the extent that ambient concentrations would be reduced. See October 1990 Draft New Source Review Workshop Manual at C.10. However, emission reductions that were made to attain the NAAQS cannot be credited as increment-expanding. If SO_2 baseline concentrations in the region were inflated by emissions from these power plants that were considered to be causing or contributing to NAAQS violations, then the SO_2 emission reductions made to bring the area into compliance cannot also be used to expand the available PSD increment, as this would be entirely inconsistent with the mandates of the Clean Air Act.

It would turn the PSD program on its head to expand increment based on pollution reductions made to comply with the NAAQS. The very essence, purpose and fabric of the PSD program is to preserve and enhance air quality in areas that meet the NAAQS. Accordingly, EPA's implementing PSD regulations, like the statute, establish the NAAQS as ironclad ambient air quality "ceilings" that shall not be exceeded under any circumstances:

> (d) *Ambient air ceilings*. No concentration of a pollutant shall exceed:
>
> (1) The concentration permitted under the national secondary ambient air quality standard, or
>
> (2) The concentration permitted under the national primary ambient air quality standard, whichever concentration is lowest for the pollutant for a period of exposure.

See 40 CFR 52.21(d).

Further, the PSD program by its plain terms applies to areas designated "as attainment or unclassifiable" for purposes of the NAAQS. CAA Sec. 161; 40 CFR 52.21(a)(2). Baseline concentrations for such "clean air" areas are specifically prescribed by statute and regulation. CAA Sec. 169(4); 40 CFR 52.21(b)(13). Thus, the benchmarks of the PSD program are deliberately delineated by law: ranging from a clean air area's baseline concentration to the NAAQS ceiling. These are the ambient air quality yardsticks. The entire PSD program is carefully calibrated to allocate increment within these touchstones, considering important public interests such as heightened protections for national parks and wilderness areas and other statutory considerations.

Pollution levels above the NAAQS exceed the maximum "[a]mbient air ceiling" established by statute and regulations. Pollution concentrations above the NAAQS are manifestly outside the permissible boundaries of the PSD program. To enlarge increment based on pollution reductions made to meet the NAAQS ceiling would be to provide "credit" for complying with the law and restoring air quality to within the PSD program boundaries. This would pervert the entire statutory terms, structure and purposes of the PSD program.

Accordingly, in this very proceeding, EPA's principal air quality modeler, Scott Bohning, explained in a meeting with Sithe officials: "Increment expansion – historically emission reduction for 4 Corners and San Juan, <u>but reduction to meet NAAQS shouldn't be used for increment expansion</u>." See attachment listed as Attachment 62 "FOIA Appeal" in the attached exhibit list (emphasis added)<u>. This prohibition is a fundamental and unyielding requirement of the PSD program.</u>

Indeed, the SO_2 emission reductions made at the Four Corners Power Plant and Units 1 and 2 of the San Juan Power Plant during the mid-1970s through the mid-1980s were made because of state and federal regulations that were intended to resolve SO_2 NAAQS compliance problems in San Juan County, New Mexico. The state and federal regulatory history of the SO_2 reduction requirements is provided in the November 9, 2006 Stamper report at pages 7-8. A review of that history makes clear that, had Public Service Company of New Mexico and Arizona Public Service Company simply complied with the SO_2 reduction requirements when first mandated to do so by 1974 as required under a federally imposed implementation plan[140], we would not now be debating whether and to what extent the SO_2 emission reductions made in the late 1970's/early 1980's at the Four Corners Power Plant and at Units 1 and 2 of the San Juan Power Plant can expand the available increment because the reductions would have been made before the applicable minor source baseline date.[141] Instead, due to litigation against EPA mainly brought by Arizona Public Service Company[142], installation of SO_2 controls was significantly delayed at Four Corners Power Plant and, to a lesser extent, also delayed at the San Juan Power Plant, and now Sithe is attempting to use those delays to its advantage to gain approval to construct a new 1,500 MW power plant in this already heavily polluted area. Sithe's attempt to take credit for these SO_2 reductions, and EPA's proposed approval of Sithe's approach, are entirely inconsistent with the mandates of the Clean Air Act and the prevention of significant deterioration program.

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[140] EPA imposed a federal implementation plan to reduce SO2 emissions at all 5 of the Four Corners Power Plant units and at Units 1 and 2 of the San Juan Power Plant by 70% in 1973. 38 Fed.Reg. 7554-7 (March 23, 1973), These regulations were promulgated because EPA found the New Mexico SIP to be deficient in failing to ensure compliance with the primary and secondary SO2 NAAQS. These power plant units were required to comply with the SO2 emission limitations by January 31, 1974, and could request EPA approval of a compliance schedule that demonstrates compliance "as expeditiously as practicable but no later than March 15, 1976." 38 Fed.Reg. 7557.

[141] In general, emissions changes that occur before the minor source baseline date become part of the baseline concentration and do not affect the increment. See 40 C.F.R. §52.21(b)(13)(ii)(b). Also, emissions changes associated with construction at existing major source that occurs after the major source baseline date, which is January 6, 1975 for SO2, also affect the available increment. See 40 C.F.R. §52.21(b)(13)(ii)(a).

[142] See 39 Fed.Reg. 10583 (March 21, 1974).

Sithe cannot obtain its permit to construct DREF without these increment expanding emissions. As shown in the November 9, 2006 modeling report by Khanh Tran, if Sithe was disallowed its use of SO_2 reductions at just the San Juan power plant alone to expand the SO_2 increment, the DREF facility would be shown to cause or contribute to significant SO_2 increment violations at Mesa Verde National Park. See also Stamper report 34-35. Specifically, with the increment expanding emissions from just San Juan Units 1 and 2 excluded from Sithe's SO_2 increment consumption modeling and all of the DREF low level emission sources properly modeled[143], the second high 3-hour SO_2 concentration was predicted to be 49.7µg/m^3 and the second high 24-hour SO_2 concentration was predicted to be 8.9 µg/m^3, both well in excess of the 3-hour SO_2 Class I increment of 25 µg/m^3 and the 24-hour Class I increment of 5 µg/m^3. Consequently, any decision by EPA Region IX to allow this unprecedented use of emission reductions intended to comply with NAAQS-imposed regulations to expand the increment for a new source must be made with absolute assurance that any such reductions are indeed creditable.

EPA is proposing to allow Sithe to take credit for SO_2 emission reductions at the Four Corners and San Juan power plants that go beyond what was necessary to attain the SO_2 NAAQS. AAQIR at 42. However, EPA failed to diligently investigate the background of the SO_2 emission reductions at the Four Corners and San Juan power plants. EPA allowed Sithe to rely on a discussion in a June 10, 1981 Federal Register preamble (in which EPA proposed approval of the New Mexico SO2 SIP) and an unorthodox method to provide its estimate of what the maximum short term average SO_2 emission rates was to show compliance with the SO_2 NAAQS. January 2006 DREF Class I Area Modeling Update, at A-1 and 4-22. See also Stamper report at 16-17. Then, any reductions in current emissions that went beyond that deemed level of control to meet the NAAQS were modeled as increment expanding emissions. AAQIR at 42.

Had EPA more thoroughly researched what was modeled to demonstrate attainment of the short term average SO2 NAAQS by New Mexico in its 1981 SIP, it would have found that the SO_2 reductions at Units 1 and 2 of the San Juan power plant should not provide for any increment expansion credit for the 3-hour average SO2 increment and at best only limited increment expansion at Unit 1 for the 24-hour average increment. See Stamper report at 36-37. Indeed, when maximum actual 3-hour and 24-hour average emission rates that currently have occurred at the San Juan Power Plant are also considered along with all DREF emissions sources, modeling based all other Sithe model inputs indicates that the second high 3-hour SO_2 concentration at Mesa Verde National Park would be 86.978 µg/m^3 and the second high 24-hour SO_2 concentration was predicted to be 8.5284 µg/m^3. *Id.* at 38. See also November 9, 2006 Tran report at 5. These concentrations reflect the high second high values where DREF would also contribute in excess of EPA's proposed Class I SO2 significant impact levels. Thus, DREF would contribute in excess of EPA's proposed Class I significance levels to violations of the 3-hour and 24-hour average SO2 increment at Mesa Verde National Park. And this analysis did not adjust any other source inputs from Sithe's DREF modeling.

With respect to the SO_2 emission reductions at the Four Corners power plant, Sithe and EPA completely ignored the fact that EPA is currently in the process of proposing a federal implementation plan (FIP) for this facility which includes limitations on SO_2 emissions. 71 Fed.Reg. 53631, September 12, 2006. As part of that proposed rulemaking, EPA should have

[143] See comment 13 above, and October 5, 2006 Tran report at 5.

performed an analysis to verify that its proposed emission limitations were sufficient to ensure attainment and maintenance of the SO_2 NAAQS in the region as required for state plans under section 110(a)(2)(A) of the Clean Air Act. Such an analysis could then be relied upon by EPA and Sithe in determining if any credit for increment expansion can be provided by the Four Corners Power Plant. Based on a review of the Four Corners Power Plant emissions that New Mexico modeled to demonstrate attainment of the SO2 NAAQS for its 1981 SIP, and a comparison to current maximum 3-hour and 24-hour average emissions, this means there are probably no SO_2 reductions at Four Corners power plant in 2003-2004 that could expand the available increment. Indeed, emissions from the Four Corners Power Plant may consume the available SO2 increment. Stamper report at 38-39.

It is important to note that the flaws in Sithe's Class I SO_2 increment analysis with respect to the Four Corners and San Juan Power Plants also carry over into Sithe's Class II cumulative SO_2 increment analysis because Sithe relied on the same SO_2 emission reductions at Units 1 and 2 of the San Juan Power Plant and at the Four Corners Power Plant to expand the available increment. Stamper report at 40. For all of the reasons discussed above, Sithe's Class I and II modeling is flawed and cannot be relied upon to ensure that the Class I or II SO_2 increments will be complied with.

Sithe Failed to Model Maximum Short Term Average SO_2 Emissions as Reflecting Current Actual Emissions.

In determining the amount of increment consumption, the permit applicant is to evaluate changes in actual emissions. According to the New Source Review Workshop Manual, for analysis of the short term (24-hour and 3-hour) average increments, the "highest occurrence" of emissions for each averaging period during the previous two years of operation must be modeled as reflecting current emissions in a PSD increment analysis. New Source Review Workshop Manual, October 1990 draft, at C.49. Sithe failed to model the current maximum SO_2 emission rates of all increment-affecting power plant units. Instead, Sithe modeled the "99th percentile" hourly SO_2 emission rate averaged over 2003-2004 for current power plant units. There is absolutely no justification for this approach in any federal regulation or guidance. As a result of using this unjustified approach to determining current emissions from power plant units, Sithe underestimated total current 3-hour average SO_2 emissions almost by a factor of 3, and only modeled about three quarters of the current total maximum 24-hour SO_2 emission rates, from all of the increment consuming power plants. Stamper report at 24-30. Thus, Sithe's SO_2 increment consumption analyses greatly underestimated the total amount of increment consuming emissions in its Class I SO_2 increment consumption analyses.

Thus, EPA cannot rely on the SO_2 PSD increment analyses provided by Sithe to demonstrate that DREF won't cause or contribute to a violation of either the Class I or the Class II 3-hour and 24-hour average SO_2 increments. Further, based on the modeling analyses performed by Khanh Tran (see November 9, 2006 Tran report), it appears there are existing violations of the 3-hour and 24-hour average SO_2 increment in Mesa Verde National Park and possibly other Class I areas. EPA's policy on this matter makes clear that such increment violations "must be entirely corrected before PSD sources which affect the area can be approved." See 45 Fed.Reg. 52678, August 7, 1980. EPA cannot assume that the planned SO_2 emission reductions at the San Juan Generating Station and at Four Corners Power Plant will remedy these 3-hour and 24-hour SO_2 increment violations. The SO_2 emission reductions that are in the March 10, 2005 San Juan power plant Consent Decree and that have been proposed to be required of the Four Corners power plant in EPA's proposed Federal Implementation Plan (FIP) (71 Fed.Reg. 53636, September 12, 2006) apply on longer term averaging periods and cannot be relied upon to ensure reductions in SO_2 emissions during each 3-hour or 24-hour period.[144] Further, the percent reduction SO_2 requirements in both the San Juan Consent Decree and in the proposed Four Corners FIP also do not guarantee any specific level of emissions because sulfur content of the coal could change over time.

EPA must resolve these SO_2 increment issues before proposing to issue a permit authorizing construction of a new power plant in the area.

16. EPA MUST NOT ISSUE THE PSD PERMIT TO DREF BECAUSE THE USFS HAS FOUND IT WILL ADVERSELY IMPACT VISIBILITY AND OTHER AIR QUALITY RELATED VALUES IN SEVERAL CLASS I AREAS

The DREF visibility modeling showed that, using FLAG procedures[145], the DREF facility will cause an adverse impact on visibility at 11 Class I areas, causing greater than a 5% change in visibility at these Class I areas. January 2006 DREF Class I Area Modeling Update at 4-13 (Table 4-5, Method 2 results). This modeling also showed that the DREF facility would cause greater than a 10% change in visibility at Mesa Verde National Park, San Pedro Parks Wilderness Area, Canyonlands National Park, Petrified Forest National Park, and the Weminuche Wilderness Area. *Id.* These levels of visibility impacts are above the levels the Federal Land Managers would typically consider to be adverse.[146] And, based on the deficiencies in the modeling methodology discussed in comment 13 above, these visibility impacts were likely underestimated.

Accordingly, the US Forest Service (USFS) submitted comments to EPA on April 26, 2006 that essentially indicated DREF's impacts on visibility and atmospheric deposition (i.e., acid rain) in USFS Class I areas would be considered adverse unless an appropriate mitigation strategy is approved and made enforceable by EPA as part of the PSD permit. See listing as **Attachment 54** on the attached exhibit list. The USFS submitted an

[144] Under the March 10, 2005 Consent Decree with Public Service Company of New Mexico for the San Juan Generating Station, there is a 7-day block average SO2 emission limit of 0.25 lb/MMBtu which appears to exclude 3 hour periods in excess of this limit due to startup, and there is a 90% SO2 reduction requirement that applies on an annual rolling average. See March 10, 2005 Consent Decree at 14-15. Neither of these emission limits will ensure that SO2 emissions are consistently reduced on a 3-hour or a 24-hour average basis. Under the EPA's September 12, 2006 proposed FIP for the Four Corners Power Plant, this facility would be subject to an 88% reduction requirement that would apply on a yearly plantwide basis. 71 Fed. Reg. 53636. The proposed FIP also includes a 3-hour average SO2 emission limit of 17,900 lb/hr that applies on a plantwide basis (*Id.*), but this limit will not ensure any sustained emission reductions from current SO2 emission levels. The annual average 88% SO2 reduction requirement will not ensure that SO2 emissions are consistently reduced on a 3-hour or a 24-hour average basis.
[145] Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report, December 2000.
[146] *Id.* at 26.

additional comment letter to EPA on September 6, 2006 to clarify its April 26, 2006 letter by stating that "the USDA-FS does find that the predicted impacts [of DREF} would be adverse." See listing as **Attachment 55** at 1 on the attached exhibit list. In its AAQIR for the DREF permit, EPA did briefly mention the USFS April 26, 2006 letter, but only stated that the USFS letter referred to a "'mitigation strategy' that Sithe had proposed to the FLMs." AAQIR at 38. Based on this adverse impact determination by the USFS, EPA cannot issue the permit until, at the very least, it addresses the requirements of the PSD permitting regulations at 40 C.F.R. §52.21(p)(3). Specifically, under federal PSD permitting regulations

> The Administrator shall *consider* any analysis performed by the Federal land manager, provided within 30 days of the notification required by [40 C.F.R. §52.21(p)(1)], that shows a proposed new major stationary source. . .may have an adverse impact on visibility in any Federal Class I area. *Where the Administrator finds that such an analysis does not demonstrate to the satisfaction of the Administrator that an adverse impact on visibility will result in the Federal Class I area, the Administrator must, in the notice of public hearing on the permit application, either explain his decision or give notice as to where the explanation can be obtained.*

40 C.F.R. §52.21(p)(3), emphasis added.

EPA has failed to meet its responsibility to address visibility impacts in its proposed issuance of the DREF PSD permit. The italicized language above makes clear that EPA cannot simply ignore the Class I visibility impacts of DREF and leave it to the FLMs and Sithe to work out a mitigation strategy. EPA has a responsibility to make its own finding of whether it agrees with the FLMs' analysis of DREF's impacts on Class I areas. And, if EPA disagrees with the FLMs'analysis, it must explain its decision.

EPA did not even mention any FLM letters indicating that DREF may have an adverse impact on visibility and other air quality related values (AQRVs) in its public notice for the DREF permit. In its AAQIR, EPA only briefly mentioned the USFS April 26, 2006 letter, but did not characterize it as a letter indicating adverse visibility or atmospheric deposition impacts. AAQIR at 38. Indeed, EPA erroneously stated in its AAQIR that the FLMs did not find any adverse impacts to visibility as a result of DREF. AAQIR at 36. EPA has also not issued any revised public notice or other statement regarding the USFS's September 8, 2006 letter that clarified the earlier USFS April 26, 2006 letter by stating that DREF would adversely impact visibility and atmospheric deposition in Federal Class I areas. (See Attachment 55). Clearly, the USFS's April 26, 2006 letter was an adverse impact finding that EPA should have responded to in accordance with 40 C.F.R. §52.21(p)(3). While EPA did discuss the regional haze modeling analysis prepared by Sithe in its AAQIR, EPA did not indicate that this analysis would offset or remedy the adverse visibility impacts predicted to occur at Federal Class I areas by the DREF visibility modeling that followed FLAG methodology. AAQIR at 44-45. Further, EPA never provided its own review and opinion on whether the construction of DREF would be consistent with visibility new source review requirements. Instead, EPA stated without further discussion of its own review "EPA has concluded that construction and operation of the proposed Facility is consistent with the requirements for visibility improvement under the Regional Haze rule." AAQIR at 45.

EPA's visibility protection new source review requirements expressly command EPA to "ensure that the source's emissions will be consistent with making reasonable progress toward the national visibility goal referred to in 51.300(a)." 40 CFR 51.307. This duty applies to EPA when it is acting in the shoes of the tribe as the permitting agency. As EPA itself has found: "In such cases, all of the rights and duties that would otherwise fall to the State [or Tribe] accrue instead to EPA." 56 Fed. Reg. 50,172, 50,173 (Oct. 3, 1991). The national visibility goal in turn has two essential dimensions: to remedy any existing visibility impairment and to prevent any future visibility impairment.

EPA's regional haze rules adopted specific regulatory requirements to carry out the national visibility goals. The haze rules establish, by regulation, "reasonable progress goals" that "must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period." 40 CFR 51.308(d)(1). EPA may not approve a permit that will add extensive visibility-impairing emissions that adversely impact visual air quality at numerous mandatory class I areas. EPA must show that the "reasonable progress goal" for these areas will be protected.

Moreover, EPA may not disregard its own regulatory prohibition on visibility degradation for the least impaired days. It must be adhered to. It is provided for directly in the implementing regulations and has been affirmed by the D.C. Circuit. When EPA adopted the anti-degradation requirement it explained "this approach is consistent with the national goal in that it is designed to prevent future impairment, a fundamental concept of section 169A of the CAA." 64 Fed. Reg. at 35,733 (July 1, 1999).

EPA's failure to demonstrate that the haze-impairing emissions from Desert Rock will comply with its own "core requirements" to protect mandatory class I areas from regional haze is plainly contrary to law. 40 CFR 51.308(d).

A review of the DREF regional haze modeling in fact would show that the modeling is flawed and that it can't be relied upon to show that emission reductions at Four Corners and San Juan power plants would more than offset DREF's adverse visibility impacts, as discussed further below.

In any case, an adverse visibility and AQRV impact determination has been made by USFS regarding the DREF permit. EPA has never properly notified the public of this determination or provided its explanation as to why it has (apparently) found that DREF won't adversely impact visibility or atmospheric deposition in nearby Class I areas in spite of the USFS's finding. Consequently, EPA has not met its responsibilities under 40 C.F.R. §52.21(p)(3), and the DREF PSD permit cannot be issued by EPA.

17. THE REFINED VISIBILITY MODELING IS FLAWED AND CANNOT BE RELIED UPON TO DEMONSTRATE THAT DREF WILL NOT ADVERSELY IMPACT VISIBILITY IN CLASS I AREAS

As described in the DREF Class I Area Modeling Update (January 2006) at 4-12, Sithe used several alternative approaches to modeling the direct visibility impacts due to the DREF facility at nearby Class I areas in addition to modeling that followed the FLAG guidance "Method 2." However, the alternatives are not technically defensible nor is it recommended as a method to be used for visibility impact determinations by the FLMs. The deficiencies in the alternative DREF visibility modeling approaches are described in the October 5, 2006 by Khanh Tran of AMI Environmental at 6. The National Park Service also commented on deficiencies in the refined visibility modeling. Those comments are discussed in Section 2.0 of the January 2006 Addendum to Modeling Protocol for the Proposed Desert Rock Generating Station. Even when all of Sithe's visibility modeling refinements are considered, Sithe's modeling still indicates that DREF would cause greater than a 5% change in visibility at several Class I areas modeled. DREF Class I Area Modeling Update (January 2006) at 4-13 – 4-15. In any case, this modeling cannot be relied upon to demonstrate that DREF will not adversely impact visibility in Class I areas.

18. THE PREDICTED PLUME BLIGHT IMPACTS FROM DREF ARE SIGNIFICANT

As discussed in the comments prepared on October 5, 2006 by Khanh Tran of AMI Environmental, the plume blight impacts from DREF alone will be significant in Class I areas in the region. See October 5, 2006 Tran report at 12.

19. OTHER MODELING STUDIES INDICATE THAT THE CALPUFF MODELING USED BY SITHE UNDERESTIMATED DREF'S VISIBILITY IMPACTS AT THE GRAND CANYON NATIONAL PARK AND OTHER CLASS I AREAS IN THE REGION

Studies were completed by the National Park Service in 2005 and 2006 that provide evidence to indicate the Calpuff modeling utilized by Sithe greatly underestimated DREF's visibility impacts in Grand Canyon National Park and most likely in other Class I areas in the region. See Barna, M. et al., 2006. *Simulation of the potential impacts of the Sithe power plant in the Four Corners basin using CAM*x, listed as **Attachment 56** in the attached exhibit list, and Schichtel, B.A. et al, 2005. *Simulation of the Impact of the SO2 emissions from the proposed Sithe power plant on the Grand Canyon and other Class I Area*s, listed as **Attachment 57** in the attached exhibit list. A comparison of these studies against the DREF Calpuff analyses was completed by Khanh Tran of AMI Environmental, and his conclusion was that "[t]he severe underprediction of Calpuff compared to the other models seriously questions the validity of the modeling results for PSD Class I increment analysis and visibility impact analysis at the Grand Canyon and other PSD Class I areas." See October 5, 2006 Tran report at 2-13 for a review of these National Park Service analyses.

The EPA must seriously consider these studies in making its finding as to whether or not the Agency concurs with the USFS's finding that DREF will adversely impact visibility and atmospheric deposition in Class I areas in the region.

20. EPA FAILED TO REQUIRE SITHE TO CONDUCT A CUMULATIVE VISIBILITY IMPACTS ANALYSIS

As commented by the National Park Service in its July 6, 2004 letter to EPA (listed as **Attachment 58** on the attached exhibit list, a cumulative visibility impacts analysis needs to be performed for the DREF project considering all other PSD permitted sources including those not constructed yet. See July 6, 2004 NPS letter to EPA, at 2. See also October 5, 2006 Tran report at 11. Yet, Sithe did not conduct a cumulative visibility analysis. Sithe's supplemental regional haze analysis is not a cumulative analysis because it only evaluated the San Juan and Four Corners power plants and did not include all PSD sources in the region. Thus, the DREF permit application is incomplete without such an analysis.

21. THE SUPPLEMENTAL REGIONAL HAZE MODELING IS FLAWED AND CANNOT BE RELIED UPON TO DEMONSTRATE THAT DREF WILL NOT ADVERSELY IMPACT VISIBILITY IN CLASS I AREAS

Sithe provided an update to its Class I modeling in March of 2006. DREF Class I Modeling Supplement (March 2006) . This analysis was done to evaluate the regional haze benefits of emissions reductions planned at the Four Corners and San Juan power plants. DREF Class I Modeling Supplement (March 2006) at 1-1. Based on this analysis, Sithe concluded "the operation of the proposed DREF will not adversely affect compliance with the goals of the Regional Haze Rule in the early part of the rule's implementation." DREF Class I Modeling Supplement (March 2006) at 5-1. It appears that EPA may have relied on this modeling to justify its proposed issuance of the DREF permit in spite of the adverse impact on visibility claimed by the USFS (as discussed in comment 16 above). Specifically, EPA stated in its AAQIR "[t]his modeling showed that visibility would improve in the area regardless of the emissions from the proposed Facility." AAQIR at 45. However, Sithe's supplemental regional haze modeling is flawed for several reasons and cannot be relied upon by EPA to justify issuance of the DREF permit in spite of the USFS's April 26, 2006 finding that the facility would have an adverse impact on Class I area visibility.

First, the March 2006 Class I modeling only considers the impacts of DREF and the Four Corners and San Juan power plants on meeting regional haze goals in the region's Class I areas. There are numerous other existing sources that are impacting visibility at the region's Class I areas. Further, there are numerous new sources of emissions that will impact the ability of the region's Class I areas to meet regional haze goals in the future, including several new coal-fired power plant units planned in the region and air emissions sources associated with significant oil, gas and coal bed methane development planned for the region. In the BLM's Farmington Field Office Area alone, the BLM has projected an increase in NO_x emissions of over 62,000 tons per year within 20 years from compressor engines associated with gas development authorized under the Farmington

RMP. See March 2003 Farmington Proposed RMP/FEIS at Summary-6 (listed as **Attachment 59** on the attached exhibit list). Thus, the March 2006 Class I analysis cannot be relied upon to demonstrate anything with respect to the area meeting regional haze goals without looking at the big picture of all existing and future emissions sources that impact regional haze in the region's Class I areas.

EPA's proposed action on Desert Rock contravenes EPA's obligations under the regional haze program and the visibility NSR requirements. As explained above, EPA must evaluate the haze-impairing emissions at Desert Rock, in conjunction with other visibility-impairing pollution in the region, in determining whether the dual reasonable progress goals for each mandatory class I area are met. The regional haze rules establish, by regulation, "reasonable progress goals" that "must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period." 40 CFR 51.308(d)(1). EPA may not approve a permit that will add extensive visibility-impairing emissions that adversely impact visual air quality at numerous mandatory class I areas. EPA must show that the "reasonable progress goals" for these areas will be protected.

The regional haze program is manifest that the plan itself is a "long-term strategy" and that compliance with the reasonable progress goal requiring an improvement in visibility involves a careful examination of the "rate of progress needed to attain natural visibility conditions by the year 2064." See 40 CFR 51.308(d)(1). EPA's regulations explain that the determination of this "rate of progress" or evaluation of the glidepath is an essential element of complying with the regional haze reasonable progress goals and that EPA must:

> "Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction measures needed to achieve it for the period covered by the implementation plan."

40 CFR 51.308(d)(1)(B).

Thus, EPA must demonstrate both durable long-term compliance with the anti-degradation requirement and the glidepath or "rate of progress" necessary to achieve natural visibility conditions by the year 2064. This demonstration of compliance is required for Mesa Verde National Park and the other numerous mandatory class I areas in the region affected by the additional visibility-impairing pollution discharged from Desert Rock and must be determined considering the overall pollution occurring and the haze-impairing pollution reasonably foreseeable in the area. EPA's regulations are clear in requiring a comprehensive assessment of emissions and require identification of "all anthropogenic sources of visibility impairment considered by the State in developing its long-term strategy. The State should consider major and minor stationary sources, mobile sources, and area sources." 40 CFR 51.308(d)(3)(iv). Further, the rules require evaluation of "[t]he anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy." 40 CFR 51.308(d)(3)(v)(G). Unfortunately, EPA has failed to carry out its own regulatory mandates under the regional haze program in proposing to approve the Desert Rock power plant.

Further, EPA must likewise evaluate all visibility-impairing sources in the area in conducting the visibility assessment for a new source under section 165(d) of the Act. EPA has long required that in carrying out section 165(d) of the PSD program the evaluation of visibility impacts from a new source includes the cumulative evaluation of the combination of sources on visibility conditions at mandatory class I areas:

> "Environmental groups and private citizens expressed the need for a policy on reviewing cumulative impacts from new sources. Rapid industrial growth is expected near some of the Class I areas. These commenters are concerned that any one source would not cause significant impairment, but the combination of sources may adversely affect air quality related values (including visibility). This would occur if the permitting authority only review the potential impacts of a new source on prevailing visibility conditions, without regard to the impacts of permitted sources not yet completed. * * *
>
> "In assessing a proposed source's impact on visibility, the reviewing authority must necessarily review that impact in the context of existing background visibility. This point does not seem debatable. The question raised by the commenters focuses on whether previously permitted sources that have not yet been constructed are part of the existing background. The EPA concludes that such sources are part of existing background. In other situations, EPA has always regarded permitted sources as part of existing background. For instance, in assessing impacts on the national ambient air quality standards, permit applicants must account for the air quality impacts of permitted, as well as constructed, sources. This treatment should be the same for visibility assessment. The EPA does not believe that a change in the proposed language for new source review is necessary to effect this implementation."

See 50 Fed. Reg. 28,544, 28,548 (July 12, 1985). Accordingly, in evaluating the visibility impacts of a proposed source on mandatory class I areas EPA and the FLMs must thoroughly consider the additional pollution from the source in light of all other visibility-impairing pollutants in fact being discharged and planned to be discharged under other projects such as oil and gas-related stationary and area sources permitted under NEPA but not yet constructed. Failure to do so is contrary to law.

Sithe's March 2006 modeling is also silent on whether regional haze goals will be met beyond the year 2010 and, given all the growth in visibility-impairing emissions expected in the region, such progress in meeting regional haze goals seems very unlikely.

Second, there are no guarantees that the emission reductions planned at the San Juan and Four Corners power plants will offset DREF's impacts during every daily period that

DREF impacts visibility and other AQRVs in Class I areas in the region. That is because the SO_2 emission reductions that are in the March 10, 2005 San Juan power plant Consent Decree and that have been proposed to be required of the Four Corners power plant in EPA's proposed Federal Implementation Plan (FIP) (71 Fed.Reg. 53636, September 12, 2006) apply on longer term averaging periods and cannot be relied upon to ensure reductions in SO_2 emissions during each 24-hour period.[147] Further, the percent reduction SO_2 requirements in both the San Juan Consent Decree and in the proposed Four Corners FIP also do not guarantee any specific level of emissions because sulfur content of the coal could change over time.

Third, there are deficiencies in March 2006 modeling methodologies, which are discussed in the October 5, 2006 Tran report. As a result of these flaws in the modeling, Sithe's March 2006 Class I modeling update may have underestimated regional haze impacts at the Class I areas modeled (and thus overstated the benefit of the San Juan and Four Corners emission reductions when considered in conjunction with the DREF emissions).

Fourth, the National Park Service raised numerous questions to Sithe and EPA about the validity of the baseline emissions and future emissions assumed for the San Juan and Four Corners power plants in the modeling. See emails from National Park Service staff to EPA Region IX and/or Bob Paine of ENSR from 3/20/06 through 4/6/06, listed as **Attachment 60** on the attached exhibit list. It is not clear that any of these issues were addressed by Sithe.

Thus, for all of the above reasons, the March 2006 supplemental regional haze modeling is flawed and is not adequate to show that DREF's adverse visibility impacts will be offset by forthcoming emission reductions at the Four Corners and San Juan power plants.

22. EPA CANNOT RELY ON THE FLM/SITHE MITIGATION STRATEGY TO ADDRESS DREF'S ADVERSE VISIBILITY IMPACTS

Although it is not certain that EPA is relying at all on the mitigation strategy that has been developed between Sithe and the FLMs, the AAQIR gives the strong impression that EPA has relied on that mitigation strategy to justify its issuance of the DREF permit.

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[147] Under the March 10, 2005 Consent Decree with Public Service Company of New Mexico for the San Juan Generating Station, there is a 7-day block average SO2 emission limit of 0.25 lb/MMBtu which appears to exclude 3 hour periods in excess of this limit due to startup, and there is a 90% SO2 reduction requirement that applies on an annual rolling average. See March 10, 2005 Consent Decree at 14-15. Neither of these emission limits will ensure that SO2 emissions are consistently reduced on a 24-hour average basis. Under the EPA's September 12, 2006 proposed FIP for the Four Corners Power Plant, this facility would be subject to an 88% reduction requirement that would apply on a yearly plantwide basis. 71 Fed. Reg. 53636. The proposed FIP also includes a 3-hour average SO2 emission limit of 17,900 lb/hr that applies on a plantwide basis (*Id.*), but this limit will not ensure any sustained emission reductions from current SO2 emission levels. Indeed, this limit was not relied on by Sithe in its supplemental regional haze modeling, and instead Sithe relied on the 88% SO2 reduction requirement that would apply on an annual average as providing for future SO2 emission reductions at the Four Corners Power Plant. The annual average 88% SO2 reduction requirement will not ensure that SO2 emissions are consistently reduced on a 24-hour average basis.

Yet, EPA did not propose to include such a mitigation strategy as part of the permit. AAQIR at 38. Indeed, the mitigation strategy was not even made available to the public, and is not listed as part of the administrative record for the proposed DREF PSD permit.

EPA cannot rely on this strategy to address DREF's adverse Class I visibility impacts or to address other air impacts unless EPA

- re-issues public notice indicating the EPA is relying on the strategy to remedy adverse visibility impacts
- proposes to make the mitigation strategy federally enforceable
- makes the mitigation strategy available for public review and comment
- demonstrates the legal and technical basis for finding that the mitigation strategy is sufficient to remedy the adverse air impacts of DREF, including providing a modeling analysis that follows proper modeling procedures, and
- provides at least 30 days for public review and comment.

According to an October 15, 2006 article in the Farmington Daily Times, it is stated that "EPA may include the mitigation strategy in a revised permit." However, if EPA is relying on the mitigation strategy in any way to justify issuance of the DREF PSD permit, then it cannot move forward with issuance of the permit now and then revise the permit later to add in the mitigation strategy as a requirement. The EPA must properly address all PSD requirements that apply to DREF before issuance of the permit.

Based on a copy of a draft mitigation strategy dated "April 2006" that Environmental Defense obtained from EPA pursuant to a Freedom of Information Act request, we find that EPA could not rely on the mitigation strategy to resolve DREF's adverse visibility impacts and justify issuance of the permit. While the April 2006 draft mitigation strategy does include some provisions that we would support as environmentally beneficial and also as necessary requirements of a DREF PSD permit (e.g., requirements to reduce mercury emissions by 90%, reduce in NO_x and SO_2 emissions, and commitment of funds to environmental improvement projects to reduce greenhouse gas emissions in the region), the mitigation strategy including the emission offset provisions are not sufficient to properly remedy DREF's visibility impacts at Class I areas in the region. The mitigation strategy would also not address other inconsistencies in the DREF permit application and proposed PSD permit with Clean Air Act requirements discussed above including the need to address CO_2 emissions and to properly consider inherently lower emitting processes in the BACT analysis and to ensure protection of the SO_2 increments in nearby Class I areas among other things. Further, because the emission offset requirements in the draft mitigation strategy could vary from year to year (i.e., the sources from which DREF obtains SO_2 emission reductions from could vary each year), it is improbable that Sithe could demonstrate that each of the various options for emission offsets would offset Sithe's adverse impacts on visibility, other AQRVs, or on the SO_2 PSD increments at Class I areas in the region during every year of operation of DREF.

Thus, EPA cannot rely on the mitigation strategy that Sithe has apparently negotiated with the FLMs as remedying DREF's adverse visibility impacts or to justify issuance of the DREF PSD permit for all of the reasons discussed above.

23. THE CLEAN AIR ACT REQUIRES THAT EPA SPECIFICALLY EVALUATE THE IMPACT OF DREF ON SOILS AND VEGETATION

The CAA's PSD requirements include a specific obligation for permitting authorities and permit applicants to evaluate impacts on soils and vegetation, CAA § 165(e)(3)(B), as well as an obligation for EPA (and other permitting authorities) to evaluate the collateral environmental impacts associated with competing technology options (169(3)).

Recently, the EAB has spoken directly to the specific obligations of the EPA regarding its consideration of impacts on soil, vegetation, species and habitat, and how those obligations relate to the permitting authority's obligation to consider collateral impacts.[148] In *In re Indeck-Elwood* the Board explained:

> [W]e find [that the] CAA provides that, in establishing BACT limits, the permit issuer is to "tak[e] into account energy, *environmental*, and economic *impacts* and other costs." CAA § 169(3), 42 U.S.C. § 7479(3) (emphasis added). We think "environmental impacts" is most naturally read to include ESA-identified impacts to endangered or threatened species. Furthermore, the CAA essentially requires an analysis of the "soils and vegetation * * * in the area potentially affected by the emissions," which may likewise be informed by ESA-identified impacts on endangered or threatened vegetative species. CAA § 165(e)(3)(B), 42 U.S.C. § 7475(e)(3)(B); *accord* 40 C.F.R. § 52.21(o). These statutory predicates would appear to provide the necessary authority to address ESA-related concerns through the provision of ameliorative conditions in the permit, particularly where the endangered or threatened species is a plant species (i.e., is "vegetation"). *C.f. Turtle Island*, 340 F.3d at 977 (finding that statute allowing action agency to issue permits entrusted action agency with discretion to condition permits to inure to the benefit of listed species). We therefore conclude that the CAA's PSD requirements and the ESA requirements are appropriately viewed as complementary in nature, such that impacts on ESA-identified threatened and/or endangered species can be taken into account when considering a PSD permit application and establishing a permit's terms and conditions. As the Ninth Circuit has noted, "an agency cannot escape its obligation to comply with the ESA merely because it is bound to comply with another statute that has consistent, complementary objectives." *Wash. Toxics Coal. v. EPA*, 413 F.3d 1024, 1031 (9th Cir. 2005) (concluding that "compliance with FIFRA [the Federal Fungicide, Rodenticide, and Rodenticide Act] requirements does not overcome an agency's obligation to comply with environmental statutes with different purposes," in particular, the ESA), *cert. denied*, *CropLife Am. v. Wash. Toxics Coal.*, 126 S. Ct. 1024 (2006); *see also Headwaters, Inc. v. Talent Irrigation Dist.*, 243 F.3d 526, 531-32 (9th Cir. 2001) (finding that FIFRA and the Clean Water Act ("CWA") have different and complementary purposes and thus the registration and labeling of a substance under FIFRA does not exempt a party from its CWA obligations).[149]

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[148] As discussed already, EPA has long recognized the obligation for a permitting authority to meaningfully consider collateral environmental impacts (*See In re North County*, 2 E.A.D. 229, 230 (Adm'r 1986), and the EAB has consistently reaffirmed this requirement.

[149] *In re Indeck-Elwood*, PSD Appeal 03-04, at 108-109, 13 E.A.D. __ (Sept. 27, 2006).

Thus, the Board has made it clear that EPA has affirmative duties under the "environmental impact" analysis prong of BACT, and those duties specifically include the consideration of impacts on soils, vegetation, and species. Where competing BACT technologies would have significantly different collateral environmental impacts – that would have distinct affects on soils, vegetation, and/or threatened or endangered species – this analysis is especially important to the meaningful participation of the public in the PSD permitting process.[150] Moreover, EPA is obligated (based on the definition of BACT in section 169) to specifically evaluate the differences in collateral environmental impacts between competing technologies.[151] Here again, because EPA did not evaluate IGCC, it has failed to meet it statutory obligation, and the public has been denied its right to comment on a vital component of the statutory decision-making process.[152]

In addition to EPA's obligation to evaluate the comparative impacts of different BACT options, the CAA imposes an independent obligation to evaluate the impacts of a proposed project on soil and vegetation in the area. *See* CAA § 165(e)(3)(B), 40 C.F.R. § 52.21(o). This long-standing requirement of the PSD program includes an obligation to perform a site-specific inventory of soils and vegetation, before the issuance of a draft permit. Such analysis must consider the variety of soils and vegetation in the area, the possibility of adverse impacts on soils and vegetation for PSD-regulated pollutants (including the possibility of adverse impacts at ambient concentrations that are lower than the applicable NAAQS, the impact of PSD pollutants – like fluoride – for which there is no NAAQS, and impacts from concentrations of pollutants that are lower than generalized screening levels),[153] the possibility of adverse impact from non-PSD

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[150] The collateral impacts analysis for soils and vegetation is important for each facet of the DREF permit, including ambient air quality assessment; technology assessments and selection (for both primary and secondary emission units); and other collateral environmental effects (such as water, solid waste, and non-PSD air pollutants) – especially when the relative benefits of other technologies (like IGCC) are considered.

[151] In this context, relevant difference may include difference in the quantity or nature of air emissions, such as NOx, SO2, CO, PM, and VOC, as well as impacts related to other factors such as water usage, solid waste handling, waste water or process water discharge, etc.

[152] One perversion created by EPA's interpretation of the Act with respect to "redefining the source" is the ability for EPA to avoid any up-front obligation to perform a comparative evaluation of mandatory factors such as collateral environmental impact, impacts on soil and vegetation, and impact on species – instead shifting the burden to commenters to essentially perform this analysis in the first instance in order to create an obligation on the part of EPA to respond in detail. Through this manipulation of the statute, EPA places itself in the position of not having to put forward any affirmative collateral impacts-related rationale for its decision which might then be subject to public scrutiny. Instead, under EPA's interpretation, it need only reasonably respond in a general fashion to comments on the subject, without actually performing any further analysis. Thus, in order to ensure that EPA meets its statutory obligations, commenters must anticipate and respond to every possible rationale that EPA might put forward (without the benefit of any discussion whatsoever in the record for the draft permit). This approach is both substantively and procedurally invalid, and places a burden on the public that is unreasonable on its face. A similar perversion exists with respect to IGCC and the core BACT obligation for a thorough technology review (discussed earlier in these comments). This serves as yet another example why EPA's interpretation of the Act simply cannot be given any credence.

[153] In particular, EPA cannot blindly rely on the 1980 *Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals* ("1980 Screening Levels). For example, the NSR Manual specifically recognizes that "there are sensitive species which may be harmed by long term exposure to low concentrations of pollutants for which there are no NAAQS" and that under certain circumstances soil and vegetation analysis "has to go beyond a simple screening." *See Indeck-Elwood*, slip op. at 38.

regulated pollutants, and the potential for any other site-specific environmental effects. *See In re Indeck-Elwood*, PSD Appeal 03-04, slip op at 31-52 (EAB Sept. 27, 2006).[154]

As a result, EPA is obligated to perform (or require of Sithe) an analysis that *specifically inventories the various soils and plant life* in the vicinity of the proposed facility (including but not limited to threatened or endangered species). The analysis must then determine whether such soils or vegetation will be adversely affected by any of the plant's emissions. At least, such analysis must include the full range of PSD pollutants (including fluoride), as well as any relevant non-PSD pollutants (including sulfuric acid mist, mercury, beryllium, etc.).[155]

Here, the draft permit for the proposed Desert Rock plant does not include an adequate discussion of potential impacts on soils and plant life.[156] Among other things, the permit application itself explains that an analysis of impacts on the many threatened or endangered species in the area of the proposed plant will be considered at a later date in connection with the process of ESA compliance.[157] This, whether adequate from an ESA standpoint or not, is clearly inadequate from a PSD perspective. The soil/vegetation analysis must be completed *before a draft permit can appropriately issue*, among other things to allow the public and other federal agencies a meaningful opportunity to comment on the analysis and any possible or likely impacts.

EPA's rationale for issuing the draft permit, found in the Ambient Air Quality Impact Report, is also shamefully deficient when it comes to meaningfully discussing possible impacts on soil and vegetation. In essence, EPA concludes that because the project will not cause a violation of the NAAQS or the PSD increments, it adequately protects soil and vegetation.[158] This analysis is

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[154] It is worth noting that the requirement to evaluate impacts on soil and vegetation apply not only to the coal-fired steam boilers but to all sources at the proposed plant, individually and in the aggregate.

[155] Among other things, acidic pollutants (or precursors), such as SO2, NOx, and hydrogen chloride can directly affect soil chemistry and have significant impacts on important habitat, vegetation, and potentially animal life (especially aquatic life). EPA and Sithe must examine the full range of these possible effects in connection with the Desert Rock project as a precursor to issuing a draft PSD permit.

[156] The original Permit Application itself stated:

> The proposed project requires Federal permits and an agreement to use trust lands of the Navajo Nation. As a result, the project requires review under and compliance with the National Environmental Policy Act (NEPA) (42 U.S.C. 4321-4347) and its implementing regulations. Under NEPA, the protection of environmental resources will be assessed and the potential impacts of the Project will be determined. This work will include a review under the Endangered Species Act (ESA) (7 U.S.C. 136; 16 U.S.C. 460 et seq.) and Section 106 of the National Historic Preservation Act (NHPA) and its implementing regulations (Protection of Historic Properties, 36 CFR 800). Steag is prepared to work with the Bureau of Indian Affairs (BIA), as the lead Federal agency under NEPA, in complying with all applicable regulations. A discussion of the Project reviews to date under the ESA is contained in Attachment 8 and work related to the NHPA is contained in Attachment 9 of this application.

Permit Application at section 6.6.4. However, the NEPA analysis was not prepared before a draft permit was issued and therefore the analysis regarding potential impact of the proposal on species (including vegetation), was not available for public comment as required by the act.

[157] Notably the ESA consultation itself, in this case, is flawed, as discussed elsewhere in these comments.

[158] EPA's discussion of soil and vegetation states in its entirety:

> The PSD regulations require analysis of air quality impacts on sensitive vegetation types, with significant commercial or recreational value, and sensitive types of soil. Evaluation of impacts on sensitive vegetation were performed by comparing the predicted impacts attributable to the project with the screening levels

facially inadequate. First, reference simply to the NAAQS and PSD increments as evidence that proposed major source will not harm soils or vegetation would essentially write the soils and vegetation analysis out of the Act – making it an unnecessary redundancy. This reading is contrary to fundamental principles of statutory interpretation; rather, EPA must require or conduct an actual, site-specific analysis of potential impacts on soil and vegetation. EPA may not substitute a discussion of compliance with NAAQS and PSD increments for an actual evaluation based on an inventory and assessment of the impacts to soils and plant life in the area of a proposed major source.[159]

Secondly, EPA may not blindly rely on the 1980 Screening Levels. As was the case in *Indeck-Elwood*, the permitting authority here has simply glossed over an incredibly important facet of the PSD analysis. In this case, EPA fails utterly to address the significance of the proximity of the plant to important natural environments on the Navajo Lands where the plant will be located and other nearby locations.[160] Instead, EPA (and the permit applicant) seeks to avoid any meaningful analysis by referencing screening criteria that have been repeatedly criticized as inadequate. The EAB itself recognized that:

> there is ample indication in the Screening Procedure itself that, in keeping with a concept of a "screening" tool, the analysis provided in the Screening Procedure may in some cases be incomplete and preliminary. In its overview section, for example, the 1980 Screening Procedure states as follows:
>
>> In keeping with the screening approach, the procedure provides conservative, *not definitive results*. * * * The estimation of potential impacts on plants, animals, and soils is extremely difficult. The screening concentrations provided here are not necessarily safe levels nor are they levels above which concentrations will necessarily cause harm in a particular situation. However, *a source which passes through the screen without being flagged for detailed analysis cannot necessarily be considered safe*.[161]
>
> Additionally, there are indications that the Screening Procedure does not purport to be complete in its coverage. The guidance observes in this regard, "[i]deally, the screening procedure should address the impacts of *all the pollutants* currently regulated under the

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> presented in A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (EPA 1980).
>
> The modeling analysis showed all impacts to be well below the screening levels. Most of the designated vegetation screening levels are equivalent to or less stringent than the NAAQS and/or PSD increments, therefore satisfaction of NAAQS and PSD increments assures that sensitive vegetation will not be negatively affected.

AAQIR at 45. The analysis in the Permit Application was almost identical, and was similarly uninformative. *See* Permit Applicant at section 6.6.2. Attachments to the proposed permit also provided not meaningful elucidation.

[159] Nor can EPA (or the permit applicant) rely on vague generalizations, such as assertions that emission of a particular kind are "trivial," without evaluating what those emissions will be and why that area expected to have no adverse impacts. *See Indeck-Elwood*, slip op at 40.

[160] Some of these important resources are referenced in the permit application at Appendix 8 (regarding threatened and endangered species). Similarly, in *Indeck-Elwood*, Illinois EPA failed entirely to address or consider impacts on an the nationally protected Midewin prairie.

[161] Citing 1980 Screening Procedure at 2-3 (emphasis added).

> [CAA], but as shown in Table 2.1, screening concentrations were found for *only half* of the regulated pollutants." Id. at 4. In fact, the guidance can only be used to screen for potential effects caused by concentrations of the pollutants in the ambient air *for only seven pollutants* because, at the time the guidance was developed, there were only sufficient data for those seven pollutants. Id. at 5; see also id. at 11, tbl. 3.1 (listing vegetation sensitivity levels for seven pollutants: sulfur dioxide, ozone, nitrogen oxide, carbon monoxide, sulfuric acid, ethylene, and fluorine). Also, the guidance notes that there was a *lack of data on chronic effects* when it was developed. In short, the 1980 Screening Procedure does not purport to address a number of pollutants with respect to which concerns have been raised here, including sulfuric acid mist, volatile organic materials (VOM), hydrogen chloride, and beryllium, and it does not consider the kinds of chronic effects that may be germane to a protected area like the Midewin.

Indeck-Elwood, slip op at 43-45.

The EAB observed as well that the data upon which the screen limits are based are *more than 26 years old* and did not even rely on native species for their analysis. *Id* at 45. Indeed, for Desert Rock the screening limits do not appear to specifically address many of the species identified in Appendix 8 of the permit application; nor does EPA claim that they do in the AAQIR.[162]

The 1990 NSR Manual, which reflects the Agency's more recent thinking about how to evaluate impacts on soil and vegetation, states that such analysis "should be based on an inventory of the soils and vegetation types found in the impact area," and an applicant must "determine the sensitivities of the plant species listed in the inventory to the applicable pollutants that would be emitted from the facility and compare this information to the estimates of pollutant concentrations calculated in the air quality modeling analysis (conducted pursuant to 40 C.F.R. § 52.21(m)) in order to determine whether there are any local plant species that may potentially be sensitive to the facility's projected emissions. . . . For those plants that show potential sensitivity, a more careful examination would be conducted. . . . *Plainly, the NSR Manual contemplates the development of site-specific information that goes beyond the scope of simple screening under the 1980 Screening Procedure*." *Indeck-Elwood*, slip op at 46 (citing and quoting the NSR Manual).[163]

With respect to Desert Rock, as was the case in *Indeck*, the permitting authority (here EPA Region 9) has treated the screening levels as if they provide conclusive proof of no impacts, and fully satisfy the Agency's and the Applicant's obligations vis a vis soils and vegetation. In fact, they do not even satisfy EPA's affirmative pre-hearing obligations to have completed and made

[162] It should be noted that the May 2004 DREF PSD permit application indicated a maximum 1-hour SO2 concentration well above the screening level for sensitive vegetation, and the June 2006 Class II Area Modeling Update shows a lower 1-hour SO2 concentration. See October 5, 2005 Tran report at 8. The reason for the discrepancy in the modeling results in unclear, but the May 2004 results at the least provide further basis for EPA to require a much more thorough evaluation of the potential impacts DREF could have on soils and vegetation in the region.

[163] While Appendix 8 of DREF's permit application may be viewed as providing an inventory of certain endangered or threatened plant species, it does not even purport to inventory all local plant species, or even all "significant" or "potentially sensitive" local vegetation. Moreover, it fails entirely to evaluate whether or which of the identified species might be adversely affected by emission from the proposed facility.

available a meaningful analysis of such impacts. As the EAB has explained, the soils and vegetation component of the PSD requirements "contemplates a *comparative analysis* of some kind between the existing baseline conditions of soils and vegetation at the site and in the potentially affected area, and the effects of the emissions on such baseline conditions" that "shall be available *at the time of the public hearing on the application for such permit*." *Indeck-Elwood*, slip op at 42-43. Nonetheless, because of EPA's unqualified reliance on the 1980 Screening Levels, the Agency has effectively failed to adequately articulate the reasons for its conclusion or adequately document its decisionmaking as part of the permit decision itself, upon which the public has a right to comment.

This appalling abdication of a critical substantive obligation demonstrates that EPA has not taken seriously its solemn statutory responsibility to fully evaluate the impact of new major sources such as Desert Rock, and in so doing EPA has denied the public its ability to meaningfully comment on EPA's decisionmaking process, and contribute constructively to the permit determination. As a result, EPA must withdraw the draft permit, prepare an appropriate soils and vegetation analysis, and provide an adequate opportunity for public comment (including public hearing) as the PSD provisions require.[164]

24. EPA FAILED TO CONSULT UNDER THE ENDANGERED SPECIES ACT SECTION 7

The EAB has specifically found that the EPA has an obligation to comply with ESA section 7 in connection with the issuance of PSD permits. As the Board acknowledged, "Section 7 of the ESA requires all federal agencies to, among other things, ensure through consultation with the Secretary of Interior (and/or the Secretary of Commerce), whose authority in the instant case is exercised by the U.S. Fish and Wildlife Service ("FWS"), that their actions are not likely to jeopardize the continued existence of any endangered or threatened species. ESA § 7(a)(2), 16 U.S.C. § 1536(a)(2)." *Indeck-Elwood*, PSD Appeal 03-04, at 18 n.35. According to the EAB, "federal PSD permits, including those issued by a delegated state, fall within the meaning of federal 'action' as that term is used in the ESA. Accordingly, ESA consultation is required in this setting when the permitting decision 'may affect' listed species or designated critical habitat. 50 C.F.R. § 402.14(a)." *Id* at 109. Moreover, the Board explained that although there is no statutory obligation to conduct the ESA and PSD exercises in concert, "to ensure compliance with the law, any consultation required under the ESA should in the ordinary course conclude prior to issuance of the final federal PSD permit." *Id* at 110.

This recognition on the part of the Board that ESA consultation is required in connection with PSD permits, and that such consultation should occur before a PSD permit is issued, reflects the fact that the purpose and intent of the ESA consultation is to ensure that the agency taking the federal action adequately considers the impact of that federal action on species and habitat *before*

[164] Again, if all EPA need do now is respond to these comments, it will have impermissibly failed to address a core substantive element of the PSD permitting process, and denied the public the ability to evaluate its specific rationale – shifting the burden to commenters to anticipate and respond in advance to all possible shortcomings that may emerge in EPA's after-the-fact analysis. At some point the question must be asked: at what stage is the public being asked unreasonably to do EPA's work for it? Clearly, in this case, the burden on the public goes too far. This cannot suffice as a matter of procedure, and EPA must withdraw and re-notice the permit for the Desert Rock plant once it has conducted the required substantive analyses.

the final decision is made. More specifically, the intent of the consultation requirement is to make sure that the agency with authority over the federal action takes steps, when necessary, to limit the impact on species and habitat in the context of that federal action. It follows from the basic intent of this requirement, that the consultation must involve the agency with authority to modify the federal action (that is agency that is the implementing authority for the particular federal action in question) and that the consultation must occur before the final action is complete.

In short, where there may be adverse impact on protected species, valid consultation under Section 7 is a prerequisite to the existence of a valid PSD permit. Once a PSD permit is issued, the construction process may proceed, so consultation that occurs after that point necessarily is inadequate to meet the dictates of the ESA – and accordingly the PSD permit cannot appropriately issue.

In this case, EPA has not only failed to conduct a Section 7 consultation before issuing its draft permit,[165] but it has indicated that it intends to conduct *no such consultation*. Instead, EPA explains that another agency entirely, the Bureau of Indian Affairs (BIA), will conduct the consultation – despite the fact that BIA has no role in and no authority to modify the relevant "federal action" – the final PSD permit.[166] EPA states in the Air Quality Impact Report:

> Pursuant to Section 7 of the Endangered Species Act (ESA), 16 U.S.C. § 1536, and its implementing regulations at 50 C.F.R. Part 402, EPA is required to ensure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of such species' designated critical habitat. EPA has determined that this PSD permitting action triggers ESA Section 7 consultation requirements. EPA is therefore required to consult with the U.S. Fish and Wildlife Service (FWS) and/or the National Marine Fisheries Service (NMFS) if an endangered species or threatened species may be present in the area affected by the permit project and EPA's action (i.e., permit issuance) may affect such species. EPA is also required to confer with the Services on any action which is likely to jeopardize the continued existence of any species proposed for listing (as endangered or threatened) or result in the destruction or adverse modification of habitat proposed to be designated as critical for such species.
>
> When a Federal action involves more than one agency, consultation and conference responsibilities may be fulfilled through a lead agency pursuant to 50 CFR § 402.07. Since the land, electrical transmission lines, and access roads required for the proposed project are located on the Navajo Indian Reservation and lands under the jurisdiction of

[165] The Board concluded that the public was not legally entitled to comment on the consultation document in connection with a draft PSD permit. Nonetheless, information regarding impact on species and habitat is undeniably relevant to EPA specific BACT-related obligation to assess collateral environmental impacts, and neither EPA nor Sithe performed any meaningful assessment of potential impacts on protected species that is available in connection with the draft permit, despite the fact that Sithe has identified dozens of species in the region that are protected either under federal law or Navajo Tribal Law.

[166] The Board specifically recognized that the issuance of a PSD permit itself was a covered "federal action." *Indeck-Elwood* at 109.

> the Bureau of Indian Affairs (BIA), the BIA will act as the lead Federal agency for purposes of fulfilling the responsibilities under Section 7 of the ESA for the project.
>
> EPA may proceed with the final permit issuance upon conclusion of consultation, review of FWS's Biological Opinion, and our determination that issuance of the permit will be consistent with the ESA requirements.

EPA's position with respect to its ESA consultation obligations flies in the face of the EAB's ruling that a PSD permit is itself a "federal action" under the ESA, and that section 7 obligates EPA to consult with the appropriate agency in connection with issuance of such a permit. EPA is mistaken that more than one agency is involved in the "federal action" of issuing a PSD permit. EPA *alone* bears responsibility for that action. Moreover, EPA and <u>not the BIA</u> has the substantive expertise to consult with appropriate agencies regarding air emission, ambient air modeling, deposition, solid waste generation, water use, and global warming, and the potential for these factors to adversely affect species and habitat.

EPA, not BIA, must consult with the FWS regarding impacts on protected species, and it must do so *before* it may issue a final PSD permit. Moreover, to the extent that any impacts on species or habitat is relevant to the collateral impacts of competing BACT option, EPA must evaluate those impacts in the context to the PSD permit process and must make such analysis available to the public for comment (and adequately respond to any public comment) before it may issue a final permit.

25. EPA'S PROPOSED DREF PERMIT FAILS TO COMPLY WITH THE EXECUTIVE ORDER TO ENSURE ENVIRONMENTAL JUSTICE

Low-income communities of color ("EJ communities") often bear a disproportionate share of industrialization's harmful byproducts, such as resource contamination and resource extraction. EJ communities may lack the political agency and economic leverage required for effective participation in environmental decision-making processes. Moreover, the persistence of structural racism in modern American society often manifests itself in the decision-making processes that affect EJ communities, as a disregard for the concerns of those communities. Seeking to mitigate the federal government's contribution to these disparities, President Clinton in 1994 signed Executive Order 12898: "Federal Actions to Address Environmental Justice in Minority Populations and Low Income Populations". Exec. Order No. 12,898, 59 Fed. Reg. 7629 (Feb. 16, 1994)("EO"). The EO recognized that environmental justice ("EJ") cannot be achieved in our nation unless federal agencies develop programs, policies, and activities specifically targeted to ensure that low-income communities of color are no longer subjected to disproportionately high levels of environmental risk and illness.[167] By doing so, the EO sought to rectify the long history of environmental injustices in these communities.

Championed by Native Americans on tribal lands, and by African-Americans, Latinos, and Asian and Pacific Islanders in large cities and small rural towns, the EJ movement addresses a

[167] *Id.* at §§ 1-101, 3-3, and 4-401.

statistical fact: people who live, work, and play in America's most polluted environments are most often people of color and the poor.[168] EJ advocates have shown that this is no coincidence: communities of color and low-income communities are often forced to host facilities that bring negative environmental impacts.

As demonstrated by a wealth of studies, and by EPA's own admission, race and class clearly play significant roles in environmental decision-making – resulting in these communities being disproportionately affected by siting decisions and the permitting of facilities.[169] In addition, it is clear that low-income communities of color are most often exposed to multiple pollutants from multiple sources.[170]

The landmark report of the United Church of Christ's Commission for Racial Justice ("Commission for Racial Justice") identified some key tools that can improve how communities respond to environmental justice. The report identified access to information, including data and scientific research, as particularly critical for communities disproportionately and adversely affected by environmental decision-making.[171] In addition, the Commission for Racial Justice reported that "institutional resistance to providing information is likely to be greater when agencies are confronted by groups, such as those among racial and ethnic communities and the poor, who are perceived to wield less political clout."[172]

To address this "institutional resistance," the Executive Order required federal agencies to adopt key tools in order to address EJ issues, including:[173]

1. to identify and address the disproportionately high and adverse human health, environmental, social, and economic effects of agency programs and policies on communities of color and low-income; and

2. to develop policies, programs, procedures, and activities to ensure that these specific impacted communities are meaningfully involved in environmental decision-making.

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[168] *See* U.S. General Accounting Office, *Siting Hazardous Waste Landfills and Their Correlation with Racial and Economic Status of Surrounding Communities*, June 1983; United Church of Christ, Commission for Racial Justice, *Toxic Wastes and Race in the United States: A National Report on the Racial and Socioeconomic Characteristics of Communities with Hazardous Waste Sites*, 1987, pp. xiii, 13-21 ("UCC Report"); and Benjamin A. Goldman and Laura Fitton, *Toxic Wastes and Race Revisited: An Update of the 1987 Report on the Racial and Socioeconomic Characteristics of Communities with Hazardous Waste Sites* (Center for Policy Alternatives and the United Church of Christ, Commission for Racial Justice, 1994), pp. 2-4; and Luke W. Cole and Sheila R. Foster, *From the Ground Up: Environmental Racism and the Rise of Environmental Justice Movement* (New York University Press, 2001), pp. 54-55, 167-83.

[169] *Id.* EPA's Office of Environmental Justice has testified that "at least 76-90 studies have consistently said that minorities and low-income communities are disproportionately exposed to environmental harms and risks" (Barry Hill, Director, Office of Environmental Justice, U.S. EPA, testimony before the U.S. Commission on Civil Rights, hearing, Washington, D.C., February 8, 2002, official transcript, p. 48).

[170] *Id. supra* note. Unfortunately, there continues to be insufficient data collection and scientific research done to clearly identify the health implications of multiple exposures.

[171] *See* UCC Report *supra* note *** at pp. 6-7.

[172] *Id.*

[173] *See* Executive Order at §§ 1-101, 3-3, and 4-401.

These requirements recognized historical inequities in the distribution of toxic pollution in impacted communities, and sought to provide assistance, policies, and programs to address these inequities. In other words, the EO creates requirements on federal agencies in at least three ways. At the outset, federal agencies are required to *identify* the impacts of their actions on the health and environmental quality of EJ communities. After identifying the EJ impacts, federal agencies are required to *address*, to the extent possible, the impacts of their actions on the health and environmental quality of EJ communities. Finally, federal agencies are required to include EJ communities in the decision-making process.

In response to the Executive Order, many agencies created internally-applicable environmental justice directives and mandates. The EPA issued an environmental justice strategy as required by the EO in 1995. EPA's environmental justice strategy does not specifically address if or how the broad goals of the EO are to be implemented in the context of a PSD permit process carried out. Accordingly, this Board's determination is directly controlled by the language of the EO and EAB decisions interpreting it. As will be shown below, the EPA's failure to fulfill its EJ responsibilities represents a violation of the EO and a deficient rendering of the requirements therein.

EPA Committed Clear Error In Connection With Its Analysis of EJ Issues by Failing to Identify EJ Issues

EPA's failure to perform a thorough analysis of environmental justice issues at the permit stage is clear error of the requirements of the EO and applicable EAB decisions.

The EO's mandate, discussed above, is clear: each Federal agency shall make achieving environmental justice part of its mission by *identifying* and addressing disproportionately high and adverse human health and environmental effects of its programs, policies and activities on minority and low-income populations. The EAB has interpreted this mandate to require that EJ issues must be considered in connection with the issuance of PSD permits by EPA. *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 174-75 (EAM 1999)(remand to supplement the record with environmental justice analysis); *In re AES Puerto Rico, L.P.*, 8 E.A.D. 324, 351 (EAB 1999), *aff'd sub nom Sur Contra La Contaminación v. EPA*, 202 F.3d 443 (1st Cir. 2000); *In re EcoEléctrica, L.P.*, E.A.D. 56, 67-69 (EAB 1997). At a minimum, EPA must issue findings that enable parties to determine whether and on what basis they should seek review and, in the event of that review, to apprise the reviewing body of the basis for that conclusion. *See, In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 175 (EAM 1999). EAP has failed to do so.

As an initial matter, EPA's failure to identify the adverse environmental effects – other than a cursory acknowledgement that issues do exist – violates its responsibilities to identify these adverse environmental impacts. Mere acknowledgement that adverse impacts may or may not exist is insufficient. Moreover, EPA's refusal to consider the adverse environmental impacts at the permit level violates its responsibility to address these impacts in its action on the permit in question, as discussed at length below.

The scope of adverse environmental impacts raised to EPA is broad. Through the submission of comments and oral testimony, local community members and interested stakeholders have raised numerous concerns. For example, commentators have raised objections to the impacts on health in light of elevated indices of asthma and other respiratory diseases in the area, based on the high levels of admittances to local clinics/hospitals and personal experience. Commentators have further expressed concerns over the interplay between health and poverty, noting that poverty exacerbates their health problems by making medical attention inaccessible, especially compelling in light of the chronic state of under-funding of health services on the reservation. Moreover, commentators have noted the high number of unpaved roads and poor infrastructure, which further aggravates the air quality and health concerns. Other examples of environmental injustices raised by commentators include: objections over water use, specifically Sithe's request to use 4,500 acre-feet of water and its effects on water resources in light of the 20-year drought and current inaccessibility to adequate water supplies by large number of Navajos; objections to land use; opposition to "pre-approval" agreements, whereby elderly and non-English speaking community members were induced to sign over grazing permits, negatively impacting grazing, agriculture, ceremonial, and cultural rituals;[174] failure to disclose documents and exhibits that would enable local communities to participate in the permitting process; concerns for agriculture and the effects of increased emissions on crops, pastoral lifestyle and income; objections to impacts on cultural, burial and historical sites of religious significance, including the desecration of burial sites and relocation/displacement of individuals, which severs the spiritual tie to the homeland;[175] and concerns over the failure to consider the cumulative impacts, including foreseeable power plant projects in the area.[176] Other concerns are outlined in the Newcomb and Burnham Chapter Resolutions – rural governmental associations – which oppose the project on a number of EJ issues.

In response to substantial public comment, EPA has generally categorized five EJ issues.[177] But simply acknowledging a few categorical subject matter areas of concern and *identifying* the issues are materially distinct. By way of legal analogy, commentators have overcome their burden of proof by raising significant EJ issues, the burden of persuasion now rests with EPA to *identify* these issues so that they may be addressed.

EPA even goes so far as to admit its shortcomings with regards to *identifying* EJ issues. EPA alludes to undefined prospective outreach and the hiring of translators, underscoring its deficient

[174] As discussed under trust and fiduciary section, commentators have voiced their opposition to the practices of Diné Power Authority officials and BHP Billiton representatives to secure the land for the Sithe power plant. Specifically, commentators object to the practice of approaching the elderly, non-English or limited English-speaking community members to sign over grazing permits and other rights to the land.

[175] Local residents have described the adverse effects of relocation and displacement, describing that soon after birth, a ceremony is held where a child's umbilical cord is buried in the land, representing a symbolic and spiritual tie between the land and people forever. Separating people from their lands through force is an affront to these symbolic and spiritual relationships. Removal from their original place of occupancy raises serious objections.

[176] The combined, incremental effects of human activity, referred to as cumulative impacts, pose a serious threat to the environment. While they may be insignificant by themselves, cumulative impacts accumulate over time, from one or more sources, and can result in the degradation of important resources. Because federal projects cause or are affected by cumulative impacts, this type of impact must be assessed.

[177] EPA has generally categorized five EJ issues: (1) lack of jobs provided to people of Navajo Nation, (2) social impacts, (3) use of local water sources as disproportionately damaging to local communities, (4) disproportionate exposure to pollutants, potential health problems (respiratory, heavy metals in fish), and (5) impacts without benefits - power goes to other locations and is not distributed locally.

rendering of such services during the permit process.[178] By pronouncing translation services at a future date without more, EPA is turning a deaf ear to the substance of the comments and their potential impact on the permit in question *now*. In addition, the assertion that translation services will be provided is speculative at best, offering nothing more than an "intention" to do something.

Further underscoring EPA's deficient identification of EJ issues, EPA announces that the project applicant has a data presentation "to better characterize the issues raised." Once again, speculative future identification (or presentation) of EJ issues without more is a failure on the part of EPA to *identify* EJ issues to inform its decisionmaking. *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 174-75 (EAM 1999)(no details regarding the EPA's environmental justice analysis required remand). The EO and EAB decisions require that they be identified during the course of a federal agency's action. To the extent EPA is relying on the data presentation, it must be identified and included in the administrative record, and opportunity to comment must be afforded. *In re AES Puerto Rico, L.P.*, 8 E.A.D. 324, 351 (EAB 1999), *aff'd sub nom Sur Contra La Contaminación v. EPA*, 202 F.3d 443 (1st Cir. 2000)(Board found EPA conducted a thorough EJ analysis at the permit stage, including air quality analyses, responses to community-conducted health studies, and efforts to receive comments in Spanish). Insofar that these pronouncements intend to comply with the requirements of EO and EAB decisions, they fall far short of the bar established by the EO and precedent.

EPA Committed Clear Error In Connection With Its Analysis of EJ Issues by Failing to Address EJ Issues

As a result of EPA's failure to *identify* EJ issues at the permit stage, EPA wholly fails to *address* EJ issues. As noted above, the EO's mandate is clear in that each Federal agency shall make achieving EJ a part of its mission by identifying and *addressing* disproportionately high and adverse human health and environmental effects of its programs, policies and activities on minority and low-income populations. The EAB has interpreted this mandate to require that EJ issues must be considered in connection with the issuance of PSD permits by EPA, and steps to address these issues taken. *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 174-75 (EAM 1999)(remand to supplement the record with environmental justice analysis); *In re AES Puerto Rico, L.P.*, 8 E.A.D. 324, 351 (EAB 1999), *aff'd sub nom Sur Contra La Contaminación v. EPA*, 202 F.3d 443 (1st Cir. 2000)(permit conditions not required by PSD regulations but within EPA's discretion were found to be an indication of its efforts to address EJ issues).

In the current instance, EPA attempts to address EJ issues by pronouncing that it "expects that these issues will be addressed through the NEPA process." EPA's efforts to delay postpone its obligation to address EJ issues until the NEPA process is an admission of non-compliance with EO and precedent on its face, and therefore is represents a failure to proceed as required by law.

[178] Translation services are an obligation that ensures proper identification of issues. It is a response to linguistic inaccessibility of non-English speaking populations, but does not address anything other the ability to participate. In other words, translation services are a procedural mechanism to ensure communication and participation in decisionmaking by non-English speaking populations.

EPA's Committed Clear Error by Failing to Include EJ Communities in its Decisionmaking

Under the EO, EPA shall to develop policies, programs, procedures, and activities to ensure that specific impacted communities are meaningfully involved in environmental decision-making. The failure to develop these policies, programs and activities has contributed to the failure to ensure meaningful involvement and participation. EPA failed to publicize public meetings through means readily accessible to local residents – e.g., radio announcements in Diné. Many Navajos are dispersed or solitary, immobilized during heavy rains or snows and inaccessible to written means of communication. Radio is a recognized medium, and commentators have raised the necessity for radio announcements that provide timely notice. In addition, EPA has failed to provide adequate translation services at the permit stage, precluding the ability of non-English speakers or those with limited English proficiency to participate in the decisionmaking process. Commentators have also raised EPA's failure to disclose documents and exhibits that would enable local communities to participate in the permitting process. EPA's committed clear error by failing to include EJ communities in its decisionmaking processes.

EPA Breached its Trust and Fiduciary Duties

The EPA has a special trust and fiduciary duty to the Navajo and to the management of their resources. From the early nineteenth century, American law has embraced the concept that the federal government owes a unique duty to Native Americans. The existence of such a duty was first articulated by John Marshall, Chief Justice of the Supreme Court, in the seminal 1831 case *Cherokee Nation v. Georgia*.[179] Marshall described the relationship between the various Native American tribes and the federal government as "perhaps unlike that of any two other peoples in existence, . . . [m]arked by peculiar and cardinal distinctions which exist nowhere else." To Marshall, the tribes were nothing less (and nothing more) than "domestic dependent nations." "Their relation to the United States," he concluded, "resembles that of a ward to his guardian." *Cherokee Nation v. Georgia*, United States Reporter 30 (5 Pet.) (1831), pp. 16, 17.

Marshall's characterization of the tribes will justifiably strike modern ears as paternalistic and condescending. *See generally* "Rethinking the Trust Doctrine in Federal Indian Law," *Harvard Law Review* 98 (1984), pp. 422, 426. By nineteenth-century standards, however, it was enlightened, holding as basic legal principle that the federal government must safeguard the interests of the sovereign peoples it absorbed in its expansion westward. Unfortunately, as the tribes were pushed onto reservations and into poverty over subsequent decades, Marshall's characterization of the tribes as dependent nations became increasingly accurate and the government's duty – its trust responsibility – grew by necessity in scope and importance. When

[179] The origins of the notion of a special duty on the part of the federal government towards the tribes arguably predates the ratification of the Constitution. For example, the Northwest Ordinance of 1787 states that "[t]he utmost good faith shall always be observed towards the Indians; their lands and property shall never be taken from them without their consent; and in their property, rights and liberty, they shall never be invaded or disturbed . . . but laws founded in justice and humanity shall from time to time be made, for preventing wrongs being done to them, and for preserving peace and friendship with them." Article III, Northwest Ordinance (1787) (reprinted in Melvin I. Urofsky, ed., *Documents of American Constitutional and Legal History* (New York: Knopf, 1989)). Unfortunately, the United States has more often than not failed to live up to these goals.

the Supreme Court wrote of the government's trust responsibilities in 1886, there was a grim reality behind its words. "These Indian tribes," the Court observed,

> are the wards of the nation. They are communities dependent on the United States – dependent largely for their daily food; dependent for their political rights. They owe no allegiance to the states, and receive from them no protection. Because of the local ill feeling, the people of the states where they are found are often their deadliest enemies. From their very weakness and helplessness, so largely due to the course of dealing of the federal government with them, and the treaties in which it has been promised, there arises the duty of protection, and with it the power. This has always been recognized by the executive, and by congress, and by this court, whenever the question has arisen.

United States v. Kagama, United States Reporter 118 (1886): pp. 384–85.

Modern courts have recognized that the general duty articulated by Marshall and his brethren obligates the federal government to consider and protect tribal interests – recognizing that tribes are not monolithic groups and tribal interests are diverse. The specific trust duty owed to tribes by the federal government in such circumstances rises to the level of a fiduciary duty – a duty similar to what lawyers owe their clients, executives their shareholders, and trustees their beneficiaries. In a typical case from 1983, the Supreme Court held that the federal government could be sued for violating its fiduciary duty and be liable for monetary damages after it mismanaged timber resources belonging to the Quinault Tribe. *United States v. Marshall*, United States Reporter 463 (1983): pp. 225–27. Justice Thurgood Marshall, writing for the Court, found that "a fiduciary relationship [between the tribe and the federal government] necessarily arises when the government assumes such elaborate control over forests and property belonging to Indians." *Id.* at 225.

As a federal agency, EPA is in a unique position to safeguard the health and well-being of the Navajo peoples, and its trust responsibility and fiduciary duty require that the government act decisively to protect their environmental and cultural resources. Nevertheless, EPA has breached these responsibilities. For example, commentators have voiced their opposition to the practices of Diné Power Authority officials and BHP Billiton representatives to secure the land for the Sithe power plant. These officials and representatives have approached the elderly, non-English and limited English-speaking community members to sign over grazing permits and other rights to the land. Commentators have forcefully objected to those practices, and requested that all communications, negotiations, monetary exchanges, etc., only be permitted on weekends when the more educated family members are home. Moreover, objections over water use, specifically Sithe's request to use 4,500 acre-feet of water and its effects on water resources in light of the 20-year drought and current inaccessibility to adequate water supplies by large number of Navajos, and concerns over land use require EPA attention. In short, these duties are incumbent upon the EPA at all times, and must inform its every action.

EPA Violates National and International Laws and Policies to Protect Religious Sites and Freedom to Worship

Also weighing on the EPA are national and international laws and policies that protect Native American religious sites and practices from degradation. In 1978, Congress passed the American Indian Religious Freedom Act (AIRFA), making it “the policy of the United States to protect and preserve for American Indians their inherent right of freedom to believe, express, and exercise the traditional religions of the American Indian . . . including but not limited to access to sites, use and possession of sacred objects, and the freedom to worship through ceremonies and traditional rites.” United States Code 42 (1999): § 1996(1). In 1996, President Clinton used an executive order to strengthen the law. In order to "protect and preserve Indian religious practices," he ordered all federal agencies to avoid adversely affecting the physical integrity of sacred sites. *See* preamble and § 1(a) of Executive Order 13007, Federal Register 61 (May 24, 1996), p. 26771.

As noted above, local Navajo residents have testified to the EPA the adverse effects that relocation and displacement would have, describing that soon after birth, a ceremony is held where a child’s umbilical cord is buried in the land, representing a symbolic and spiritual tie between the land and people forever. Separating people from their lands unwillingly or through trickery is an affront to these symbolic and spiritual relationships. By allowing Sithe to displace and relocate Navajo community members, EPA is adversely affecting the deep spiritual and religious connection to the land, contrary to AIRFA and President Clinton's executive order.

International principles further strengthen the case for the agency's intervention. Recognizing the value of water and land resources to indigenous society, culture and religion, the United Nations Draft Declaration on the Rights of Indigenous Peoples asserts their “right to maintain and strengthen their distinctive spiritual and material relationship with the lands, territories, [and] waters . . . which they have traditionally owned or otherwise occupied or used, and to uphold their responsibilities to future generations in this regard.” Draft United Nations Declaration on the Rights of Indigenous People (Aug. 26, 1994), art. 25 at 552 (reprinted in International Legal Materials 34 (1995): p. 541). The Navajo may be denied their fundamental right to "manifest [their] religion or belief in worship, observance, [and] practice," guaranteed them by the International Covenant of Civil and Political Rights, which the United States recently ratified. International Covenant on Civil and Political Rights, General Assembly Resolution 2200A (XXI) (Dec. 16, 1966, entry into force Mar. 23, 1976), art. 18 (reprinted in Center for Human Rights, *Human Rights: A Compilation of International Instruments* (New York: United Nations, 1988) (U.N. Sales No. E.88.XIV.1), p. 26). The Covenant was ratified by the United States on September 9, 1992. See Public Notice 1853, Federal Register 54 (1993): p. 45934.

Sithe Has Not Analyzed Air Toxics Impacts and Associated Health Impacts

As discussed in the October 5, 2006 report by Khanh Tran of AMI Environmental, a detailed quantification and health impacts assessment should have been completed for the DREF permit application to fully address public health and environmental justice concerns. October 5, 2006 Khanh Report at 8-9. EPA cannot issue the permit without receiving this data and analysis and without making it available to the public for review and comment.

26. EPA'S PROPOSED DREF PSD PERMIT MUST INCLUDE REQUIREMENTS TO ENSURE SITHE IS HELD TO ITS REPRESENTATIONS REGARDING THE DREF FACILITY THAT WERE MADE IN ITS PSD PERMIT APPLICATION

EPA's proposed permit for DREF fails to include any provisions to ensure that the DREF facility cannot be modified from the source parameters that were reflected in the DREF PSD permit application. Yet, the EPA's proposed PSD permit does not even specify the date of the PSD permit application for DREF, nor does EPA's AAQIR for that matter. Without references to the representations made in the permit application, Sithe could change its design in ways that could change air pollutant dispersion or alter BACT analyses without limitation.

Accordingly, EPA must, at a minimum, include a description of the proposed DREF facility that defines the type of coal to be burned, the MW capacity (net and gross), and the maximum heat input capacity of each boiler. Further, EPA must include a provision in the proposed permit stating that construction of the DREF facility must be in accord with the information provided in the May 2004 PSD permit application, that EPA must be notified of any deviations from the information included in the DREF permit application, and that any significant deviation from the representations made by Sithe in its DREF PSD permit application may be grounds for suspension or revocation of the permit. Provisions such as these are commonly required in PSD permits, and provide a necessary assurance to the public and federal, tribal and state regulatory agencies that construction of a significantly different facility, or significant modification of the DREF facility, cannot be done without further evaluation.

27. EPA HAS FAILED TO COORDINATE THE PSD PERMIT PROCEEDING, NEPA REVIEWS AND REVIEWS CONDUCTED UNDER SECTION 309 OF THE CLEAN AIR ACT TO THE MAXIMUM EXTENT FEASIBLE AND REASONABLE AS REQUIRED BY LAW

40 CFR 52.21(s) provides that EPA's PSD permit reviews "shall be coordinated with" environmental reviews conducted under NEPA and under section 309 of the Clean Air Act "to the maximum extent feasible and reasonable." This mandate is common sense and effectuates good public policy. Unfortunately, EPA has failed to adhere to its own regulatory command. EPA has steadfastly declined public requests to review the EIS under NEPA (and EPA's associated comments under section 309) in parallel with the PSD permit review. Further, documents obtained under FOIA, demonstrate that EPA is deliberately moving ahead with the permit with disregard for the NEPA proceeding in response to the entreaties of Sithe officials: "Gus [Sithe] said they need air permit before the EIS. Ann [EPA] said they understood and didn't expect NEPA would slow that down and assured they are not waiting b/c of NEPA and are proceeding with work on the permit." See listing as **Attachment 62** in the attached exhibit list ("FOIA Appeal"). This is contrary to the mandate for coordination under the law.

Thank you for considering these comments. Please notify us regarding any EPA action on the DREF permit.

Sincerely,

Mark Pearson/Mike Eisenfeld
San Juan Citizens Alliance
PO Box 2461
Durango, Colorado 81302
(970) 259-3583
mpearson@frontier.net

Anna M. Frazier
Dine' Citizens Against Ruining Our Environment
HC-63, Box 263
Winslow, Arizona 86047

Patrice Simms
Senior Project Attorney at Law
Natural Resources Defense Council
1200 New York Ave. NW, Suite 400
Washington, D.C. 20005
(202) 289-2437
psimms@nrdc.org

Vickie Patton
Senior Attorney
Environmental Defense
2334 N. Broadway
Boulder, CO 80304
(303) 440-4901
vpatton@environmentaldefense.org

John Nielsen
Energy Program Director
Western Resource Advocates
2260 Baseline Road
Boulder, CO 80302
(303) 444-1188
jnielsen@westernresources.org

Matt Baker
Executive Director
Environment Colorado
1536 Wynkoop
Denver, CO 80202
(303) 573-3871
mbaker@environmentcolorado.org

Sanjay Narayan
Staff Attorney
Sierra Club
85 Second St., Second Floor
San Francisco, CA 94105
(415) 977-5769
sanjay.narayan@sierraclub.org

Nicole Rosamarino
Conservation Director
Forest Guardians
312 Montezuma Ave. Suite A
Santa Fe, NM 87501
(505) 988-9126
nrosamarino@fguardians.org

Roger Clark
Air Director
Grand Canyon Trust
2601 N. Fort Valley Road
Flagstaff, AZ 86001
(928) 774-7488
rclark@grandcanyontrust.org

Ann B. Weeks
Litigation Director
Clean Air Task Force
18 Tremont St., Suite 530
Boston, MA 02108
(617) 624-0234
aweeks@catf.us