BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	
PROPOSED NEW CAIR SO_2, CAIR NO_x	)	R06-26
ANNUAL AND CAIR NO_x OZONE	)	(Rulemaking – Air)
SEASON TRADING PROGRAMS, 35 ILL.	)	
ADM CODE 255, CONTROL OF EMISSIONS	)	
FROM LARGE COMBUSTION SOURCES,	)	
SUBPARTS A, C, D, AND E	)	

Notice of Filing

To: See Attached Service List

PLEASE TAKE NOTICE that on January 5, 2007, we filed with the Clerk of the Illinois Pollution Control Board the attached POST-HEARING COMMENTS a copy of which is attached hereto and hereby served upon you.

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Dated: January 5, 2007

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Post-Hearing Comments

NOW COMES Participants the Environmental Law & Policy Center ("ELPC"), by itself and on behalf of American Lung Association of Metropolitan Chicago ("ALAMC"); Environment Illinois, by and through its attorneys the Chicago Legal Clinic; and the Sierra Club (collectively, "Environmental Advocates"). Pursuant to Hearing Officer's Order of December 20, 2006, the following post-hearing comments are submitted to the Illinois Pollution Control Board. Through these comments, the Environmental Advocates urge that the Illinois Environmental Protection Agency's ("IEPA") proposed Clean Air Interstate Rule ("CAIR") rule be amended in the following three ways. The renewable energy and energy efficiency set-asides should be increased so as to better meet its own renewable energy goals. Secondly, Clean Air Set Aside ("CASA") proposed for circulating fluidized bed boilers ("CFBs") should be removed, as CFBs are not a clean coal technology. Finally, the fuel weighting factors should be eliminated, as they discourage the use of cleaner fuels in energy production.

Along with these comments, we are also providing documents requested at the hearing of November 28, 2006 during the testimony of Charles Kubert.

I. The Energy Efficiency and Renewable Energy Set Aside Should Be Increased.

In order to best meet the pollution reduction goals of CAIR and the Governor's own renewable energy plan, the renewable energy and energy efficiency ("RE/EE") set asides in the IEPA's CAIR rule proposal must be increased. Encouraging RE/EE projects through allowance set-asides directly contributes to the stated goals of the CAIR. Specifically, RE/EE allow replacement and reduction of a portion of the energy need that is currently being delivered to Illinois consumers through the burning of fossil fuels. This replacement and reduction will result in a decrease in the burning of fossil fuels, leading to a decrease in Illinois' emissions of NO_x and SO_2.

Illinois has great potential for the production of renewable energy from wind, solar power, and biofuel. Renewable energy production projects will benefit from assignment of allowances corresponding to the amount of energy they produce. IEPA has acknowledged that while the Governor's plan calls for 10% of Illinois energy to come from renewable sources by 2015, the current CAIR proposal will only lead to an offset of 5-8% of future need. (Cooper 10/12/2006 Tr. at 95-97). The renewable energy and energy efficiency set asides included in CASA, currently set at 12%, should be raised to 15%, with an annual increase of 1% to a maximum of 20%. This will best allow the Illinois CAIR rule to work toward both the Governor's plan and its own goals. (Kubert 11/29/2006 Tr. at 179; *see also*, Kubert 11/28/2006 Am. Test. at 7).

In response to requests made during the November 29, 2006 hearing, documents are attached to this comment as exhibits. Exhibit 1 (in response to request on 11/29/2006 Tr. at 156) is a Department of Defense study on the effects of wind turbines on radar. The study concludes that with proper planning and site selection, any conflict between radar technology and wind turbines may be mitigated.

Exhibits 2 and 3 (in response to request on 11/29/2006 Tr. at 158-9) are relevant to the subject of the economic impact on wind power versus coal power. Exhibit 2 is a report published by the National Renewable Energy Laboratory. The study concludes that "adding new wind power can be more economically effective than adding new gas or coal power and that a higher percentage of dollars spent on coal and gas will leave the state." Exhibit 3 is a study by the Union of Concerned Scientists. The study shows that developing wind power instead of coal and natural gas power can have a net benefit to a state's economy.

Exhibit 4 (in response to request on 11/29/2006 Tr. at 172-3) includes the press release and presentation by the office of Governor Blagojevich of his plan for the future development of energy in Illinois. This plan calls for meeting 10% of Illinois' electricity needs with renewable resources by 2015.

Exhibit 5 (in response to request on 11/29/2006 Tr. at 157) is a document from the Energy Information Administration comparing the generation costs of wind power, new coal, and natural gas, among other energy sources and shows that the generation costs of RE/EE are competitive with coal.

The Rule Should Not Provide Incentives for Circulating Fluidized Bed Boilers.

Circulating fluidized bed boilers ("CFBs") should not receive CASA credits. Why?

- Controlled CFBs are not lower in NO_x emissions than controlled pulverized coal ("PC") boilers;
- CFBs do not achieve the low NO_x emissions that IGCC plants do; and
- CFBs emit more greenhouse gases than PC boilers.

IEPA's explanation of its reason for including CFBs in the CASA makes clear the lack of justification for CFBs receiving CASA credits. Aside from the unsubstantiated assertions that

CFBs "result in very low pollutant emissions," and "very low emission that can be achieved" with CFBs, the Technical Support Document for IEPA's proposed rule ("TSD") contains no support for giving incentive credits to CFBs. (TSD at 112.) IEPA was apparently merely responding to concerns of "the coal-fired power plants for fluidized bed boilers" and "listened to concerns there, that there should be some set-asides available to them, and, in fact, we [IEPA] do provide some set-asides to fluidized bed boilers." (Ross, 10/10/2006, 9:00 A.M., Tr. at 46-47.)

In addition, these concerns apparently came from an existing CFB because the IEPA "in particular, for the fluidized bed boilers . . . decided for a look back until 2001 to give some level of credit to companies that undertook what we [IEPA] would consider a clean technology, clean coal project." (Ross, 10/11/2006, 1:00 P.M., Tr. at 135.) However, companies undertook these projects independent of any consideration of the availability of credits or other financial rewards or incentives under the CASA. Clearly, the economics of installing the technology were such that no credit or reward was needed and it makes no sense to provide one retroactively. Because IEPA puts forward no persuasive reason for including CFBs in the CASA, and because CFBs emit more NO_x and greenhouse gases than controlled PC boilers and IGCC plants, CFBs should be removed from the CASA.

a. CFBs do not lead to reduced NO_x emissions compared to PC boilers.

When looking at real-world operations, CFBs do not emit less NOx than PC boilers. In fact, the opposite is the case. While CFBs may be lower emitting than PCs when looking at uncontrolled emissions, CFBs are not lower emitting once controlled. By focusing on what "can be achieved" with CFBs or the "result[ing] . . . emissions" from CFBs, IEPA underscores what should be considered—the end point, not the starting point. (TSD at 112.) Air quality impacts are the reason for this rulemaking. Consequently, real world operations and actual emissions impacts on air quality should be considered when deciding categories worthy of incentives. In this day and age, new coal fired power plants are all built with controls. Therefore, it is emissions from controlled CFBs compared to emissions from controlled PC boilers that should be considered because that is demonstrative of what the actual emissions will be.

Historically, new CFBs have not been required to install the most effective NO_x controls—SCR—while PC boilers have. *See, e.g.*, Babcock & Wilcox Report at 3 (Ex. 6). Therefore, PC boilers achieve lower NO_x emissions levels and have lower NO_x permit levels than CFBs. CFB permit levels for NO_x have generally been in the 0.07 to 0.08 lb/MMBtu range. *See, e.g.*, Indeck, Spurlock, and Highwood Permits (Ex. 7, 8, 9). PC boilers, however, have been permitted in the 0.04-0.05 lb/MMBtu range. *See, e.g.*, Trimble Permit (Ex. 10). In fact, there are at least thirty PC units in the US operating with ozone season SCRs emitting less than 0.05 lb/MMBtu NO_x as measured by an hourly average. *See* Erickson Paper at 8 (Ex. 11).

In sum, new PC boilers, which generally use the most modern NO_x controls, achieve approximately 30% lower NO_x emissions than CFBs, which generally are built without the best performing NO_x controls. Consequently, there is no justification for offering incentives for CFBs if in real world operations they do not achieve lower emission levels than PC boilers.

b. <u>CFBs do not achieve emissions levels comparable to IGCC.</u>

Furthermore, the CASAs categorize IGCC plants with CFB plants for the same "Clean Coal Technology" incentive and also opened the category up to additional similar projects. IEPA Proposed Rule, § 225.460(e). The TSD discusses the eligibility for other projects to receive credits under this section for the "Clean Coal Technology" incentive and states that projects that use "technologies that achieve comparable emission rates" to IGCC or CFBs may be eligible for the set aside. (TSD at 112.) This further highlights the inappropriateness of allowing CFBs to receive credits as a "Clean Coal Technology" because CFBs and IGCC projects themselves do not achieve comparable NO_x emissions rates.

As pointed out above, CFB permit levels for NO_x have generally been in the 0.07 to 0.08 lb/MMBtu range. *See, e.g.*, Indeck, Spurlock, and Highwood Permits (Ex. 7, 8, 9). Contrast such levels to expected NO_x emissions levels for recently proposed IGCC plants which average .039 lb/MMBtu, resulting upwards of 45% lower NO_x emissions. See Table 1 (Ex. 12). Since CFBs do not perform nearly as well as IGCC, they should not be included in the same category of incentives.

Table 1[1]

Pollutant	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
	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu
SO2	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
NOx	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

Consequently, not only do CFB NO_x emissions levels not come close to being as low as IGCC NO_x emissions levels but it would also be impossible to determine what other projects ought to be eligible under the clean coal technologies category. The IEPA is required to determine whether a project is "similar in its effects as the projects specifically listed in section 225.460 (c)." § 225.460(e). If the two projects listed in section 225.460(c), are not similar in their effects—that is, similar in their emissions rates as articulated in the TSD—there is no

[1] Taken from "Comments on EPA's Proposed Construction Permit for Sithe Global Power to Construct the Desert Rock Energy Facility," submitted to Robert Baker by Dine Citizens Against Ruining our Environment et al., at 35 (Nov. 13, 2006) (Ex. 12).

clarity on what emissions rates new projects ought to be achieving in order to receive clean coal technology credits. For these reasons, CFBs should be removed from the CASA.

c. <u>CFBs emit 15% more greenhouse gases.</u>

Finally, and perhaps most egregiously, not only are CFBs emitting more NO_x than controlled PC boilers and IGCC plants, but CFBs pose a very serious additional environmental and health concern: CFBs emit more N_2O, a potent greenhouse gas, than PC boilers. Comparatively, CFBs emit approximately 15% more global warming pollutants than PC boilers.

> N_2O has a GWP (Global Warming Potential) 296 times that of CO_2. Because of its long lifetime (about 120 years) it can reach the upper atmosphere, depleting the concentration of stratospheric ozone, an important filter of UV radiation. N_2O is emitted from fluidized bed coal combustion; global emissions from FBC units are 0.2 Mt/year, representing approximately 2% of total known sources. N_2O emissions from PC units are much lower. Typical N_2O emissions from FBC units are in the range of 40-70 ppm (at 3% O2). This is significant because at 60 ppm, the N_2O emission from the FBC is equivalent to 1.8% CO_2, an increase of about 15% in CO_2 emissions for an FBC boiler. Several techniques have been proposed to control N_2O emissions from FBC boilers, but additional research is necessary to develop economically and commercially attractive systems.

2003 National Coal Council Report "Coal-Related Greenhouse Gas Management Issues" at 7 (Ex. 13). In fact, SNCR, the NO_x controls most commonly used on CFBs, increase the amount of N_2O.

Once again, this weighs against providing a CASA incentive for CFBs. Creating an incentive for a technology that emits 15% more global warming pollutants than the alternatives is contrary to both state and IEPA goals. Both the Governor and IEPA Director Doug Scott have publicly stated that reducing global warming pollutants is a state priority. The Governor is committed to a “long-term strategy by the state to combat global climate change, and builds on steps the state has already taken to reduce greenhouse gas (GHG) emissions, such as enhancing the use of wind power, biofuels and energy efficiency.” Press Release, “Governor Launches

Global Warming Initiative," Office of the Governor (Oct. 5, 2006). In launching his Global Warming Initiative, Governor Blagojevich stated

> We've worked hard in Illinois to become a national leader in reducing toxic pollutants like mercury, sulfur dioxide and nitrogen oxide. The next front is greenhouse gases. The impact of global warming from greenhouse gases in Illinois and around the globe could be devastating. We can't wait for the federal government to act because experts have warned that if we don't address global warming within the next decade, it may be too late to avoid serious and irreversible consequences.

Id. Similarly, IEPA Director Scott chairs the Illinois Climate Change Advisory Group. Regarding global warming, he has stated, "By acting now we can take important steps to reduce our greenhouse gas emissions and realize the economic development benefits that strategies to confront climate change can offer." *Id*. Consequently, by endorsing CFBs and providing incentives for them, IEPA and the state are acting completely contrary to state policy on global warming. For that reason, CFBs should be removed from the CASA.

In sum, incentives for CFBs are inappropriate because CFBs emit more NO_x than controlled PC boilers, emit significantly more NO_x than other technologies receiving the same "clean coal" incentives (IGCC), and emit 15% more global warming pollutants than PC boilers. It is incumbent upon the IPCB to correct the course of this rule and remove "clean coal" incentives for CFBs.

II. Illinois Should Adopt A Fuel Neutral Approach In Allocating NO_x Allowances To Specific Sources In Order To Encourage The Use of Cleaner Fuels and Modern, Well-Controlled Electric Generating Units.

The original federal CAIR proposal was fuel neutral, meaning it did not include an adjusted fuel-weighting calculation to determine NO_x emission credit allowances. 69 Fed. Reg. 4610 (2004). Fuel neutrality has generally been the approach taken for NO_x allocation under the

NO_x SIP call. *Alternative* NO_x *Allowance Allocation Language for the Clean Air Interstate Rule*, prepared by State and Territorial Air Pollution Program Administrators (STAPPA) and the Association of Local Air Pollution Control Officials (ALAPCO), August 2005, at 5. According to STAPPA and ALAPCO, a fuel neutral allocation system that does not differentiate between coal and non-coal units "…even[s] the playing field by treating all units the same. Among other things, this allows the trading program to do a more effective job of determining the most cost effective compliance mix." *Id*.

U.S. EPA received several comments in opposition to the fuel neutral approach to determine NO_x emission credit allowances. Predictably, virtually all of the comments in opposition were submitted by the operators of coal-fired electric generating units or their trade associations. For their part, states which commented on CAIR focused on other issues. For example, Illinois EPA's comments of March 30, 2004 were largely supportive of CAIR, except that Illinois EPA asserted that CAIR as originally proposed did not go far enough or fast enough to protect public health and to achieve attainment with NAAQS (Ex. 14). From the perspective of Illinois EPA, further reductions of emissions from fossil fuel fired power plants were practicable, warranted, cost effective and long overdue. Illinois EPA did not object to the fuel neutral approach in allocating NO_x emission credit allowances.

When CAIR was promulgated in final form, it was no longer fuel neutral, and included an adjustment factor of 1.0 for coal, 0.4 for gas and 0.6 for oil. 70 Fed. Reg. 25231 (2005). The adjustment factor functioned in two ways. First, U.S. EPA used the adjustments in order to establish the final NO_x statewide budgets. *Id*. By virtue of the application of the fuel adjustment factors, Illinois' statewide budget actually increased when compared with its budget under the original CAIR proposal. The Illinois budget for 2009-2014 grew from 73,613 tons to 76,230 tons of NO_x. *See* Table V-2 at 70 Fed. Reg. 25231 (2005) and Table VI-10 at 69 Fed. Reg. 4620 (2004). The budget for 2015 and thereafter grew from 52,973 to 63,525 tons of NO_x. *Id*. Illinois, which had argued for deeper reductions, now found itself with more NO_x allowances by virtue of the elimination of fuel neutrality.

However, having given Illinois additional NO_x allowances, CAIR in its final form explicitly does not require Illinois or any other state to use the fuel allocation factors in distributing allocations to individual sources. This is the second way that fuel allocation factors can be used. For U.S. EPA, it was entirely left to individual states to decide whether to use a fuel neutral or fuel weighted system in making allocations to individual sources. 70 Fed. Reg. 25231 (2005). In the words of U.S. EPA:

> It is important to note that the methodology by which the NO_x State budgets are determined need not be used by individual States in determining allocations to specific sources. As discussed in section VIII of this document (Model Trading Rule), EPA is offering States the flexibility to allocate allowances from their budgets as they see fit.

Id. According to U.S. EPA, any differences between the model federal rule and state rules in allocating NO_x allowances "…are possible without jeopardizing the environmental and other goals of the [CAIR] program." *Id*. at 25278. Simply, Illinois is free to allocate NO_x credits in a fuel neutral manner. A fuel neutral allocation is the approach to which IEPA had no objection in the initially proposed CAIR, and the approach which will achieve the deeper, faster reductions it seeks. The Environmental Advocates urge the Illinois Pollution Control Board to eliminate or modify the fuel weighting component of the proposed Illinois rule.

In making this recommendation, the Environmental Advocates are not alone among Illinois stakeholders. In the fuel weighted system that is now a component of the proposed

Illinois rule, coal-fired power plants are the clear beneficiaries by comparison to their oil- and especially gas- fired counterparts. Coal-fired power plants are allocated NO_x allowances on a 1:1 to basis, oil-fired power plants receive a 0.6:1 allocation and gas-fired EGUs receive only a 0.4:1 allocation. Because Illinois will freely distribute initial credits, coal-fired power plants will receive a significant asset by comparison to their non-coal competitors. Because they will receive proportionately greater credits, the market will be designed to perpetuate this arbitrary advantage.

The immediate losers as a result of this market inefficiency are unmistakably identified in the IEPA's Technical Support Document. According to IEPA, there are 229 existing generating units that will be subject to the CAIR NO_x Annual, the CAIR SO_2, and the CAIR NO_x Ozone Season trading programs. (TSD at 25.) Of these units, the losers are the 170 gas and oil fired boilers and combustion turbines identified by IEPA. *Id*. The winners are 59 coal-fired power plants. The IEPA's reasoning for using a fuel weighted system that benefits one sector at the expense of others has been consistent throughout these proceedings, and it is twisted. According to IEPA, coal-fired EGUs have an "inherently higher emission rate" by comparison to their cleaner EGU counterparts, and therefore deserve an advantage in the form of a disproportionate allocation of credits. (TSD at 35.) In other words, oil- and gas-fired EGUs are being punished for using an inherently cleaner fuel. This is twisted because it disadvantages an EGU that generates an equivalent unit of energy with lower emissions by comparison with a coal-fired unit. It moves Illinois farther from, not closer to, IEPA's stated objective of promoting cleaner, sustainable energy alternatives. *Id*.

Many oil and gas fired EGUs are also being punished by virtue of operating more modern, well-controlled facilities than their coal-fired counterparts. This is clear in the testimony of Jason Goodwin. In his testimony, Mr. Goodwin repeatedly called attention to the fact that under the Illinois allocation scheme, many gas-fired units will receive disproportionately fewer credits not only because they use cleaner fuel, but also because they were constructed with modern pollution control equipment. Mr. Goodwin noted this was particularly unfair for "…those that have undergone control technology review within the recent past and have demonstrated compliance with best available control technology requirements." (Goodwin 11/28/2006 Tr. at 21). Goodwin states "…the reduction in terms of allocations that are available to gas-fired units ignores the basis and understanding that the facilities that we're talking about…represent…not only the best available emission and technology threshold, but it also satisfies the most available emission rate technology for similar sized facilities throughout the country." *Id*. at 22. For Mr. Goodwin, one particularly worrisome consequence of allocating disproportionately fewer credits to well-controlled gas-fired units is that if they operate at a greater capacity than their baseline years, they may be forced to purchase credits from older, poorly controlled coal-fired competitors. Because the facilities already employ state-of the-art emission controls, Mr. Goodwin noted, "There really is no option for us to make any sort of additional reductions at the facility itself." *Id*. at 26. Putting modern, well-controlled and cleaner facilities at such disadvantage is a far cry from IEPA's stated objective. In the Technical Support Document, the Agency asserts "…Illinois EPA believes that is good environmental policy to provide more allowances to sources that operate more efficiently, install air pollution control equipment, and upgrade their equipment. (TSD at 35.)

Perhaps just as importantly, Mr. Goodwin also testified that the new Illinois allocation system represents a change in the approach under the existing NO_x seasonal trading system. Mr. Goodwin testified, "We see this as an unfortunate departure from the NO_x trading program, which has been in effect and operational within Illinois for several years. We view the past experience with the trading program as being highly successful and question the basis for deviating from that concept." (Goodwin 11/28/2006 Tr. at 21-22.) In light of the success of the fuel neutral NO_x seasonal trading program and the IEPA's stated policy to provide more allowances to efficient, modern facilities, why has IEPA proposed a fuel weighted system? Mr. Goodwin's explanation is succinct, "Clearly, Illinois is strongly oriented to coal generation." (*Id*. at 27.) On the issue of fuel weighting or fuel neutrality, the Illinois rulemaking proposal may be politically savvy, but is not reasonably related to the stated purposes of encouraging cleaner energy generation.

Illinois would not be alone among states in establishing a more fuel neutral system for allocating NO_x allowances. Several states at various stages of the rulemaking process have decided a more fuel neutral allocation would be a better option. According to Jason Goodwin, Alabama and Arkansas propose fuel neutral allocation systems. (Goodwin 11/28/2006 Tr. at 92). At preliminary stages in the rule development process, both Massachusetts and Virginia have indicated an intention to propose fuel neutrality. Wisconsin's proposed rule is fuel neutral.[2]

Other states have modified the fuel allocation system to a two-tier system. South Carolina has adopted fuel weighting but with only two fuel factors, 1.0 and 0.6. South Carolina stated the following:

> The Department presently supports the language in the Federal rule that allocates allowances adjusted for fuel type. The reason for our support is because this system recognizes the fact that coal combustion devices have inherently higher NO_x emissions than oil or natural gas sources. Thus, a fuel neutral allocation system would provide a disproportionately larger share of NO_x allocations to oil and gas fired units. However, the Department recognizes that such a system may tend to promote higher-emitting fuels. Furthermore, we acknowledge that a fuel-neutral allocation system would be much easier to implement. Currently, the

[2] http://www.dnr.state.wi.us/org/aw/air/HOT/8hrozonestd/cairbart/CAIRNOxallocations060605.pdf Last accessed 21 December, 2006

> information needed to calculate the ratios of fuel types to heat input for facilities using different fuels is not available or is difficult to obtain. Also, the calculations of adjusted heat input would probably be more complicated and time consuming. Thus, we are continuing to look into our options regarding this issue and appreciate further input. The Department is proposing modified fuel adjustment language that allocates allowances adjusted for fuel type at two levels instead of three as proposed in the Federal rule. The Department believes this represents a compromise between those stakeholders that support fuel-adjusted allocations in recognition of the fact that coal combustion devices have inherently higher NO_x emissions and those stakeholders that believe that such a system provides a subsidy for dirtier fuels. Under this proposal, the Department is proposing to use a fuel adjustment factor of 1.0 for all sources that are permitted to burn any amount of coal. For sources that are not permitted to burn coal, the unit's heat input would be subject to a fuel adjustment factor of 0.6. [3]

A similar fuel neutral approach has been proposed in Texas. Finally, as noted, STAPPA and ALAPCO have developed a model rule for state CAIR implementation that eliminates fuel weighting, a copy of which is attached to these comments. *Alternative NO_x Allowance Allocation Language for the Clean Air Interstate Rule*, prepared by State and Territorial Air Pollution Program Administrators (STAPPA) and the Association of Local Air Pollution Control Officials (ALAPCO), August 2005.

IEPA's stated goals for CAIR are to allocate more credits to sources that operate efficiently and install effective pollution control equipment. Throughout the CAIR process, IEPA pressed for faster, deeper reductions through practicable, warranted, cost effective and long-delayed pollution control upgrades at poorly controlled facilities. When measured against its own goals, the fuel weighting system IEPA proposes fails. Fuel weighting rewards operators of poorly controlled facilities and facilities that use inherently higher polluting fuel. IEPA rewards these operators by freely allocating credits that are in inverse proportion to its

[3] http://www.scdhec.gov/eqc/baq/pubs/CAIR/BAIICAIRCAMR.pdf#xml=http://www.scdhec.gov/cgi-in/texis.exe/Webinator/search/xml.txt?query=CAIR&pr=page&rorder=500&rprox=500&rdfreq=500&rwfreq=500&rlead=500&sufs=1&order=r&cq=&id=44ff994a2a last accessed: 21 December 2006.

objectives. This not only benefits historically dirtier facilities, it punishes facilities that already employ cleaner fuels and modern pollution control equipment. Fuel weighting is not mandated by U.S. EPA, it is a retreat from the successful NO_x seasonal trading program, and it is not a feature of the STAPPA and ALAPCO model rule. The Illinois Pollution Control Board should address the contradiction between IEPA's stated goals and its proposed allocation system by eliminating or significantly modifying the fuel weighting component of the rule.

For all of the above reasons, it is recommended to the Illinois Pollution Control Board that the IEPA's proposed CAIR rule be amended to increase the renewable energy and energy efficiency set-asides, remove any allowance incentives granted to fluidized boilers, and eliminate the included fuel weighting factors.

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CERTIFICATE OF SERVICE

I, Faith Bugel, hereby certify that on January 5, 2007 I filed the attached POST-HEARING COMMENTS. An electronic version was filed with the Illinois Pollution Control Board and copies were served via United States Mail to those individuals included on the attached service list.

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Dated: January 5, 2007

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REPORT TO THE CONGRESSIONAL DEFENSE COMMITTEES

The Effect of Windmill Farms On Military Readiness

2006

Office of the Director of Defense Research and Engineering

EXECUTIVE SUMMARY

SECTION 358, NATIONAL DEFENSE AUTHORIZATION ACT FOR FISCAL YEAR 2006 (PUBLIC LAW 109-163)

REPORT ON EFFECTS OF WINDMILL FARMS ON MILITARY READINESS.
Not later than 120 days after the date of the enactment of this Act, the Secretary of Defense shall submit to the Committee on Armed Services of the Senate and the Committee on Armed Services of the House of Representatives a report on the effects of windmill farms on military readiness, including an assessment of the effects on the operations of military radar installations of the proximity of windmill farms to such installations and of technologies that could mitigate any adverse effects on military operations identified.

Overview

There is growing public and private sector interest in generating electrical power using wind energy. According to the Department of Energy, over 60,000 megawatts of wind power capacity is in operation worldwide with over 10,000 megawatts installed in the United States. These systems are largely comprised of installations of up to several hundred wind turbines with rotating blades reaching to heights of up to 500 feet. The numbers, height and rotation of these wind turbines present technical challenges to the effectiveness of radar systems that must be carefully evaluated on a case-by-case basis to ensure acceptable military readiness is maintained. For many cases, processes are in place to allow responsible federal authorities to complete determination of acceptability of wind turbine impacts on military readiness. However, since wind energy use in the United States is dramatically increasing, research and interagency coordination is warranted to enhance capability for completing timely determinations and developing measures for mitigating readiness impacts. This report focuses on the effects of wind farms on air defense and missile warning radars and the resulting potential impact on military readiness. Its scope is limited to these specific subjects and is based on the current level of understanding regarding interactions between such defense systems and state-of-the-art wind turbines.

The report begins with a brief introduction of the key principles of radar systems, describes in what circumstances wind farms might cause problems for the Department and under what circumstances such wind farms would not cause problems. Radar test results from multiple flight trials near wind farms performed by the United Kingdom Ministry of Defence are discussed. The results from those flight trials documented that state-of-the-art utility-class wind turbines can have a significant impact on the operational capabilities of military air defense radar systems. The results demonstrated that the large radar cross section of a wind turbine combined with the Doppler frequency shift produced by its rotating blades can impact the ability of a radar to discriminate the wind turbine from an aircraft. Those tests also demonstrated that the wind farms have the potential to degrade target tracking capabilities as a result of shadowing and clutter effects.

The Department sponsored a testing campaign as a part of this study to establish a technical database on the radar cross section and Doppler behavior of a modern utility-class wind turbine that can be used to support development of future mitigation approaches. This testing was performed using the state-of-the-art Air Force Research Laboratory Mobile Diagnostic Laboratory (MDL) which is certified to perform radar measurements to the most stringent national standards. The test procedures, samples of the experimental test data, and calibration methodology have been documented in a report. The full data set has been made available to U.S. radar contractors and government-sponsored researchers.

The report discusses a number of mitigation approaches that might be employed to reduce the impact wind turbines can have on an air defense radar. Only three methods so far have been proven to be completely effective in preventing any impairment of primary radar systems. Employment of these or other approaches that could produce marginal, but acceptable, impacts on defense capabilities need to be assessed on a case-by-case basis.

The report discusses potential wind farm impacts on Department test and training capabilities, security on and around defense installations, through introduction of electromagnetic noise in special electronic system testing areas, and the general environment.

The Department recognizes that wind energy use is dramatically increasing in the United States. Development of additional mitigation technologies is important to enable robust expansion of wind generation capacity to continue while concurrently maintaining defense capabilities for our Nation. The also describes exploratory development efforts initiated by the Department to advance the state of maturity of other mitigation approaches that could be employed in the future are also described in the report.

Appendices are provided describing the policies employed in several NATO countries to govern wind farm development and how wind farms can impact the performance of U.S. Comprehensive Test Ban Treaty monitoring systems.

Conclusions and Recommendations

Given the expected increase in the U.S. wind energy development, the existing siting processes as well as mitigation approaches need to be reviewed and enhanced in order to provide for continued development of this important renewable energy resource while maintaining vital defense readiness. The Department of Defense strongly supports the development of renewable energy sources and is a recognized leader in the use of wind energy. As one of the largest consumers of energy, the Department is keenly aware of the budgetary pressures that recent increases in the cost of energy have created for all Americans and continues to invest in the development of alternative energy sources. However, the Department is also mindful of its responsibility to maintain its capabilities to defend the nation.

Consequently, the Department, as a result of this study, makes the following conclusions and recommendations regarding the challenges and areas for further attention, in coordination with other Federal agencies, to allow for construction of wind turbines while maintaining defense readiness capabilities:

- Although wind turbines located in radar line of sight of air defense radars can adversely impact the ability of those units to detect and track, by primary radar return, any aircraft or other aerial object, the magnitude of the impact will depend upon the number and locations of the wind turbines. Should the impact prove sufficient to degrade the ability of the radar to unambiguously detect and track objects of interest by primary radar alone this will negatively impact the readiness of U.S. forces to perform the air defense mission.
- The mitigations that exist at present to completely preclude any adverse impacts on air defense radars are limited to those methods that avoid locating the wind turbines in radar line of sight of such radars. These mitigations may be achieved by distance, terrain masking, or terrain relief and requires case-by-case analysis.
- The Department has initiated efforts to develop additional mitigation approaches. These require further development and validation before they can be employed.
- The analysis that had been performed for the early warning radar at Cape Cod Air Force Station was overly simplified and technically flawed. A more comprehensive analysis followed by development of appropriate offset criteria for fixed-site missile early warning radars should be performed on an expedited basis.
- Wind turbines in close proximity to military training, testing, and development sites and ranges can adversely impact the "train and equip" mission of the Department. Existing processes to include engagement with local and regional planning boards and development approval authorities should be employed to mitigate such potential impacts.
- Wind turbines located in close proximity to Comprehensive Test Ban Treaty monitoring sites can adversely impact their ability to perform this mission by increasing ambient seismic noise levels. Appropriate offset distance criteria should be developed to mitigate such potential impacts.
- The Federal Aviation Administration (FAA) has the responsibility to promote and maintain the safe and efficient use of U.S. airspace for all users. The Department defers to the FAA regarding possible impacts wind farms may have on the Air Traffic Control (ATC) radars employed for management of the U.S. air traffic control system. The Department stands prepared to assist and support the FAA in any efforts the FAA may decide to undertake in that regard.
- The National Weather Service (NWS) has the primary responsibility to provide accurate weather forecasting services for the nation. The Department defers to the NWS regarding identification of impacts wind farms may have on weather radars and development of appropriate mitigation measures. The Department stands prepared to work with the NWS in this area on NWS identified mitigation measures that have the potential to benefit Department systems.

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1. INTRODUCTION

Focus of Study

This report has been prepared in response to Section 358 of the National Defense Authorization Act for Fiscal Year 2006 concerning the impacts wind farms may have on U.S. military readiness, to include an assessment on operation of military radar installations and technologies that could mitigate any adverse effects identified. The intent is to ensure that the accelerating development of wind energy systems within the United States will occur in a manner that also preserves the capability of U.S. military forces to protect the homeland.

This report specifically discusses how megawatt (MW) class state-of-the-art (SOA) wind turbines can impact domestically sited U.S. air defense and missile warning radar systems. Wind turbines of this size are typically considered to be "bulk-power utility-scale" units often employed in "wind farms" to provide electricity for local or regional power grids. Within the context of this report, the term "wind farm" will be employed to denote a collection of two or more megawatt class wind turbines within a geographical area that may range in size from a few acres to hundreds of acres.

The report does not attempt to consider impacts that could occur from small "homeowner" type wind turbine systems. Modern versions of such units are relatively small in physical size, with generating capacities in the low kilowatt (kW) range. They are not anticipated to have significant impact unless located directly adjacent to a domestic defense system. This is not considered to be a highly probable occurrence since land directly adjacent to domestic defense systems is generally under the positive control of the federal government.

The report describes existing as well as possible future mitigation techniques that could be employed to mitigate impacts for megawatt wind turbines. Finally, it describes science and technology efforts already being pursued to develop additional future mitigation approaches.

Brief History of the Development of Wind Energy Systems

According to the history page of the Danish Wind Industry Association (www.windpower.org), the first automatically operated windmill employed to generate electricity was built in Cleveland, Ohio, in 1888. Figure 1 provides an illustration of this system that appeared on the front page of the 20 December 1890 edition of *Scientific American.* While physically large, the 17 m diameter rotor was only able to generate 12 kW of power.

For the next 40 years a variety of low-power wind turbine designs were developed. Some were employed to provide power to local electrical grids or at remotely located farms not connected to electrical grid networks. The development of bulk power utility-scale turbines, units with generating capacities on the order of 100 kW or more, appears to have begun in earnest in the 1930s in multiple nations but this did not lead to the development of any major commercially operated "wind farms" for bulk power generation. Subsequent advances in turbine technologies during the 1960s and 1970s did, however, provide the technical basis for current approaches.

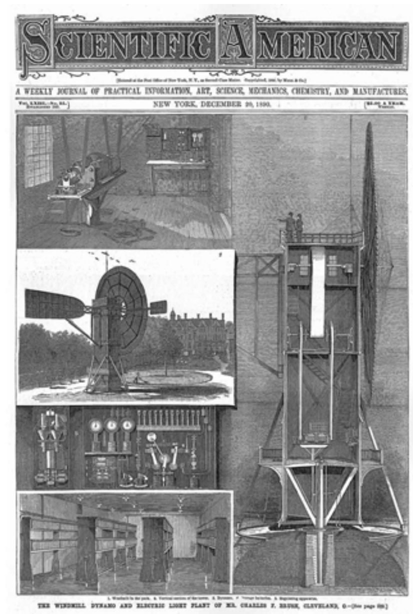


Figure 1. *Scientific American* illustration of the 1888 Brush Windmill in Cleveland, Ohio

One of the earliest large wind farms in the United States was built, starting in 1982, in the Altamont Pass area of California. The wind farm is actually a collection of a number of different turbine designs owned and operated by several different organizations. The Altamont Pass Wind Farm currently consists of more than 4700 units; the vast majority being older 100 kW capacity units with, in 2003, a reported combined net generating capacity on the order of 494 MW [1]. The significantly greater per-unit generating capability of current SOA turbines means that far fewer, but physically much larger, turbines can be employed to generate this level of power. For size comparison purposes, note that a typical 1980s vintage 100 kW capacity wind turbine, such as those at Altamont Pass, has a blade length on the order of 8 m and is mounted on towers 24 to 30 m high. In contrast, a SOA 1.5 MW unit may have blades on the order of 35 to 40 m in length mounted on support towers 60 to 80 m or more high.

In terms of future trends, a recent report by the European Wind Energy Association [2] discussed the numerous technical factors related to growth in turbine sizes and capacities over the past several years. While it was expected that rotor sizes and rated capacities may continue to increase as higher strength materials are employed in fabrication of turbine blades and other components, it also indicated that economic and operational factors could exert limitations. Consequently, the report concluded that significant growth in size beyond the 5 MW class units currently in development would not be automatic. Table 1 provides typical dimensions for SOA megawatt class turbines currently available from two manufacturers. Similar size/capacity units are also produced by a number of other firms.

Table 1. Physical data for representative SOA turbines

Manufacturer & Data Source	Rated Capacity (MW)	Rotor Diameter (m)	Rotor Speed (rpm)	Tower Height (m)
GE (www.gepower.com)	1.5	77	10-20	65-100
GE (www.gepower.com)	3.6	104	8.5-15	Site dependent
Vestas (www.vestas.com)	1.65	82	11-14	59-78
Vestas (www.vestas.com)	4.5	120	10-15	Site dependent

Fundamentals of Radar[*]

Radar systems are widely employed for many commercial and defense applications. In its simplest form (Figure 2), a radar is a sensor system utilizing electromagnetic radiation in the radio frequency (rf) spectral region, spanning from approximately 3 MHz to around 100 GHz, and consisting of a transmitter, an antenna, a receiver, and a processor. The transmitter emits pulses of energy in the form of rf waves that propagate through the atmosphere. An object, typically referred to as the target, in this radar beam will reflect some of this energy back to the radar. This reflected energy is collected by a receiving antenna for processing. The basis of operation of a specific radar sensor system is determined by the content of the information contained in the reflected radiation and how it is processed.

The degree of difficulty encountered in processing the radar reflection from the target of interest depends upon the strength and variability of the signal at the receiver relative to other sources. For example, the strength of the reflected signal received by the radar will depend on the power of the transmitter, the distance to the target, atmospheric effects, the radar cross section (RCS) of the target, the possible presence of intervening physical objects, and the antenna geometry. The radar may also receive reflected radiation from other objects such as trees, buildings, vehicles, and hills, as well as direct radiation emitted by other natural and man-made rf sources, such as the atmosphere, cell phone towers, television and radio antennas, and electrical generators.

Signal variability can occur due to motion of the target and changes in the intervening physical environment, such as those caused by rain or hail, as well as reflections from wind-blown trees. A number of other effects arising from the inherent thermal electronic noise in the radar sensor, the physics of antenna systems, the atmosphere and intervening objects on the propagation of electromagnetic radiation also

[*] The term “RADAR” was an American acronym created in 1941, with the letters selected from the words **ra**dio **d**etection **a**nd **r**anging. The use of this acronym has become so prevalent that it is now generally accepted as a common word in English and rarely capitalized.

must be taken into account in determining the performance fidelity of a radar sensor system.

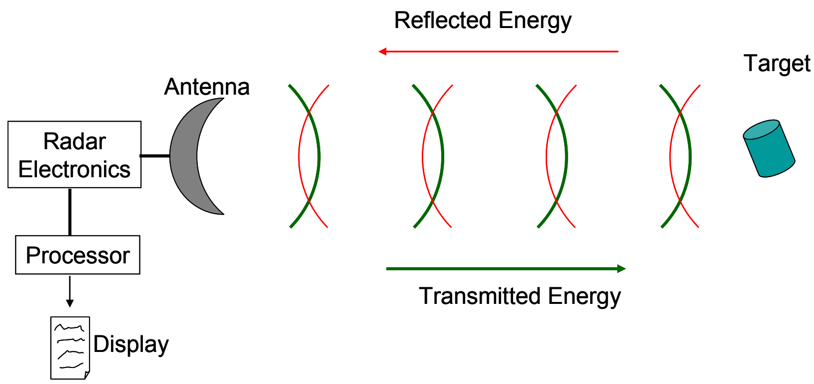


Figure 2. Illustration of a basic radar system

The term "clutter" has been established to encompass any unwanted reflected signal that enters the radar receiver and can interfere with the determination of the desired attributes of the target of interest. Discussions in following sections of this report will provide examples of the effects of clutter that interfere with resolving behavior, such as detecting the presence of a valid target, discriminating between two closely spaced targets, and subsequently tracking the motion of all targets of interest.

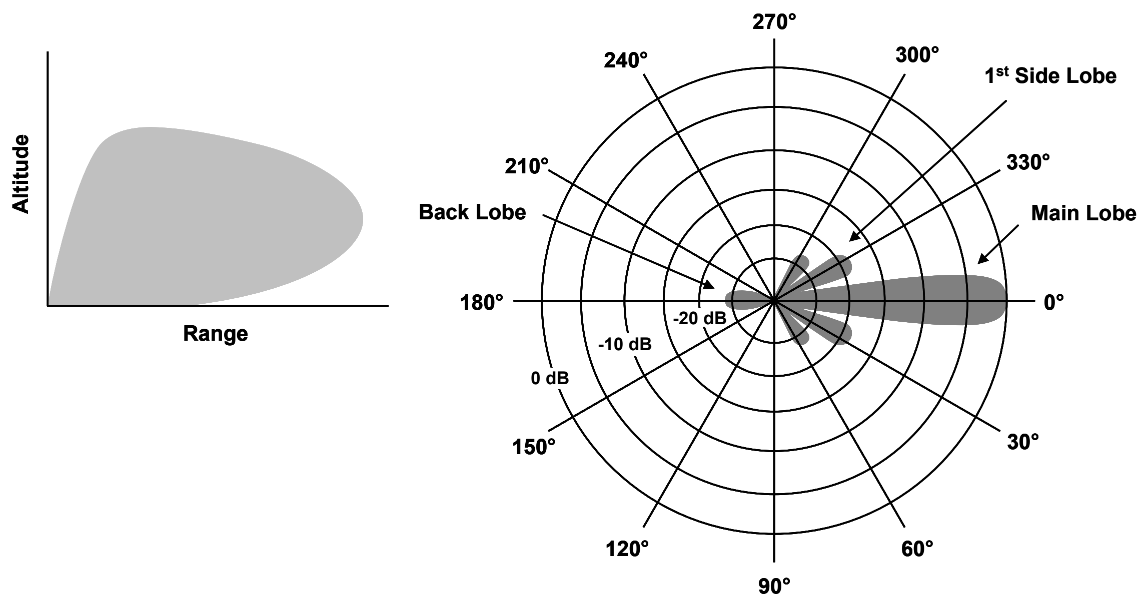
At the most basic level, the ability to successfully process the reflected radiation depends on the strength of this signal relative to the background noise inherent in the radar electronics. This is characterized as the signal-to-noise ratio (SNR). Increasing the radar-to-target distance dramatically decreases the intensity of the received signal. For example, if the distance between the radar and the target is doubled, the signal returned decreases by a factor of 16. Since a design goal for a defense radar is to detect targets at the maximum range possible, the ability to sense very low signal strengths is essential. At the extreme, the absolute minimum level of noise that can occur in a system is fundamentally limited to the thermally induced noise in the sensor electronic components and thermal radiation from the atmosphere. However, the actual level of noise, to include clutter effects, that a radar sensor must deal with are significantly greater than this theoretical limiting case.

Many of the attributes characterizing a radar system involve values spanning many orders of magnitude. For example, the SNR for a radar system can vary by more than 1 million during operation. The decibel (dB), a logarithmic ratio of two quantities, is used to describe these ratios in terms of smaller numerical values. For example, an SNR value of -30 dB means that the signal strength is 1/1000 of the strength of the noise. Similarly, for a value of 10 dB, the signal would be 10 times greater than the noise. The dB unit will be used frequently in the sections to follow. For convenience to the reader, Table 2 provides examples of the conversion of dB to the equivalent factor.

Table 2. Decibel (dB) equivalents for some common numerical ratios

dB	-50 dB	-30 dB	- 10 dB	-3 dB	0 dB	3 dB	10 dB	30 dB
Factor	1/100,000	1/1,000	1/10	½	1	2	10	1,000

Due to the finite size and shape of an antenna, the emitted power is distributed in a lobe-shaped pattern. The center (or main) lobe contains the majority of the radar power, but the secondary, tertiary, etc., lobes (side lobes) can have sufficient energy to introduce clutter into the system. Figure 3 illustrates the main, side, and back lobes for a 2-dimensional (2-D) radar. Figure 3a provides a range versus elevation plot of the -3 dB (half power) point of the beam relative to the peak power level. Figure 3b provides an azimuth beam shape plot, where power level as a function of azimuth angle is plotted relative to peak main lobe power.



a. Main lobe as function of range and altitude

b. Main, side, and back lobe amplitudes as a function of azimuth angle

Figure 3: Notional main, side, and back lobes of a 2-D radar

Multiple side lobes can exist in both the vertical and azimuth directions with respect to the axis of the main lobe. In a well-designed radar system, the power level of the side lobes will be significantly below that of the main lobe.

Radars can detect sufficiently strong reflections from objects located in the antenna side lobes. Side lobe suppression methods have been developed to reduce the influence of such signals. The ultimate effectiveness of the side lobe attenuation provided will depend significantly upon the power level of the side lobe beam and the strength of the reflected signal in comparison to the primary signal of interest.

The range of an optical viewing systems is ultimately limited by the optical or "geometric" horizon. For radar systems, the electromagnetic radiation propagating through the atmosphere is refracted (effectively bent), with the result that a radar beam can be reflected by an object beyond the geometric horizon. Analysis of this refraction effect has indicated that for radar frequencies, the radar horizon can be reasonably approximated by employing a "4/3 earth model." In this approximation, a geometric line of sight is calculated, but using an "effective" radius for the earth equal to the actual radius of the earth multiplied by the factor 1.33, as illustrated in Figure 4.

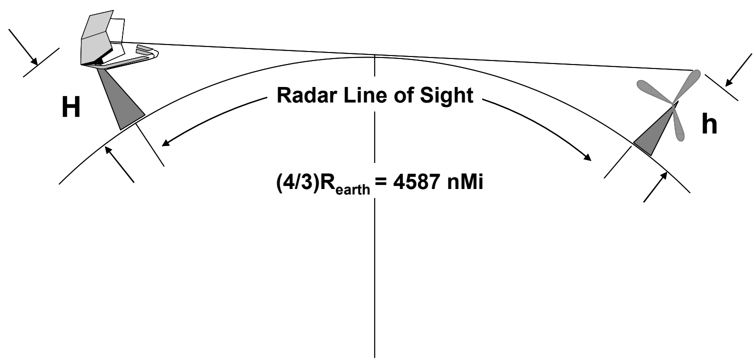


Figure 4. Geometric approximation to estimate radar line of sight

Objects in the path of an electromagnetic wave affect its propagation characteristics. This includes actual blockage of wave propagation by large individual objects and interference in wave continuity due to diffraction of the beam by individual or multiple objects. The effect caused by either of these is often termed to cause "shadowing" of the radar beam.

The presence of a single tall building within the radar field of view provides a typical example for blockage. Since a tall building effectively blocks all propagation of a radar rf wave, the zone immediately behind the building will not be illuminated by the radar. If the building is close to the radar there will be zones of complete and partial shadowing. This is illustrated in Figure 5.

In the region where the radar wave is completely blocked it is impossible to detect any object in that region. In contrast, detection is still possible in the zone of partial blockage but with greater difficulty. In this region both the level of illumination from the radar and the reflected signal from the target will be weakened by the partial blockage. This is one form of the shadowing effect.

The second form of disruption occurs because of a phenomenology referred to as "diffraction." Near-field and far-field diffraction effects were first studied by the Danish physicist Christian Huygens and the French physicist Augustin-Jean Fresnel. As illustrated by Figure 6, whenever a traveling wave encounters a line of objects, the objects will disrupt the propagation of the wave in that locale. This phenomena can be illustrated as propagation of spherical waves from each of the objects. These waves will combine constructively and destructively on the far side of the objects. In the zone of the disrupted waves the reflection of the radar signal is significantly different from areas where it has not been disturbed. These differences include variations in intensity and phase angle and are a function of original frequency and the spacing of the objects causing disruption.

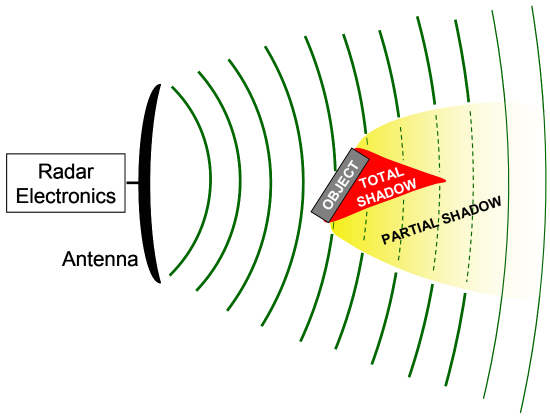


Figure 5. Regions of partial and complete blockage of radar illumination

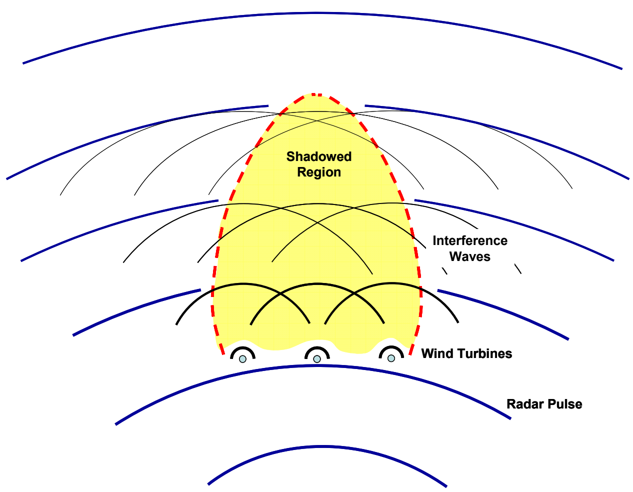


Figure 6. Effect of a diffraction grating on a propagating wave

These disruption effects will occur both for the original transmitted wave and the wave reflected back to the radar by a target. As such, the ability to detect a target in this zone will be degraded. This is the form of shadowing that has been raised as a concern in relation to wind farms since the spacing of turbines over a field of view can create this type of diffraction effect for a radar.

The strength of the reflected signal, whether the object is illuminated by the main lobe or by one or more side lobes, depends not only upon the power level of that illumination but how "large" a reflector of radar energy the object is. This "size" factor is commonly referred to as its radar cross section (RCS). Objects with a large RCS will reflect, proportionately, a larger amount of radar energy than an object with a lower RCS and thus be easier to detect. RCS is normally expressed in terms of "decibel square meters" (dBsm), a logarithmic expression of an object's radar reflecting surface area. Figure 7 provides typical RCS values, in terms of both square meters and dBsm, for a number of common items, including that of a 1.5MW SOA wind turbine. Unlike the other objects depicted in Figure 7, the RCS for the wind turbine is a combination of a near-zero Doppler reflecting surfaces consisting of the tower and nacelle and variable Doppler reflecting surfaces consisting of the turbine blades. The near-zero Doppler portion of the reflected signal generally will not cause a problem in a well designed radar. However, the broadly spread variable Doppler portion of the reflected signal from the wind turbine can often exceed that produced by an aircraft.

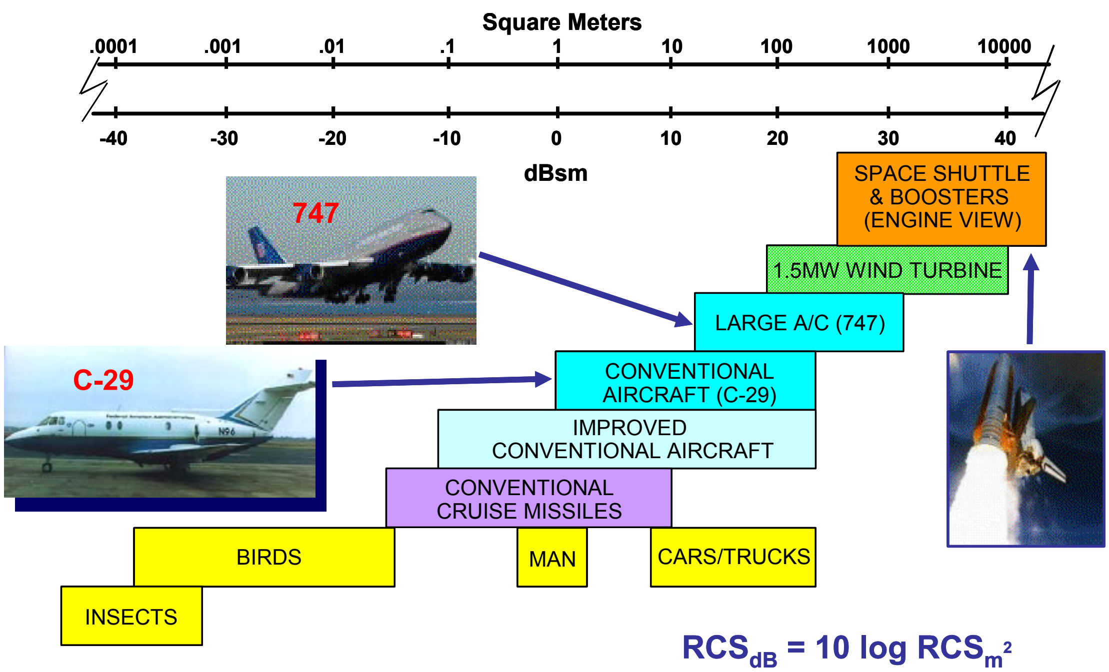


Figure 7. RCS values for several common objects

The magnitude of the RCS of an object is dependent upon the angle, both in bearing and elevation, from which it is observed by the radar. Figure 8 illustrates how the RCS value for the C-29 "business jet" included in Figure 7 varies as a function of bearing angle, where observing the airplane from a nose-to-tail perspective is denoted as a 0-degree bearing angle. These values were measured at 2.9 GHz, with a "look down" angle from the vertical of 15 degrees. Modifying the viewing angle or changing the frequency band used for the measurement will change the measured RCS characteristics.

Radar systems have been designed and deployed for a wide variety of applications and missions. These include air defense radars, air traffic control (ATC) radars, missile warning radars, and weather radars. The design of each of these radar sensor systems depends on the mission requirements, the phenomenology to be exploited, and the available technology. For example, current generations of weather radar systems exploit the Rayleigh scattering properties of precipitation, i.e., scattering of radiation having wavelengths, on the order of 10 cm, much larger than the characteristic size of rain, hail, and snow particles. The computational schemes employed are designed to reduce the effects of "clutter" to obtain the desired weather information. Surveillance radars, in addition to having a capability to sense weather-related phenomena as just described, exploit the scattering properties of objects much larger than the wavelength of the radar. They also employ computational schemes specifically tailored to produce desired surveillance information. The mission challenges introduced by clutter to the performance of radar systems are discussed in the following sections of this report.

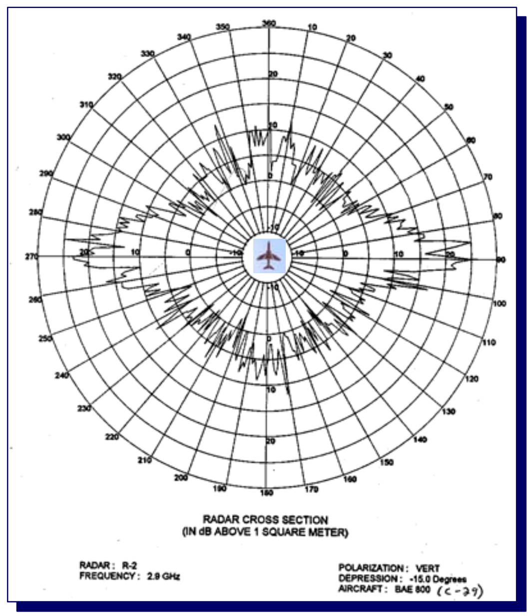


Figure 8. RCS values for C-29 aircraft as a function of view angle

Advances in electronics, processor, and computational technologies have enabled a number of radar system performance enhancements. A key capability provided by these advances and employed in virtually all modern radar systems today is the capacity to sense pulse-to-pulse phase differences, thus enabling the Doppler effect to be exploited.

The Doppler effect, specifically the shift in frequency of the reflected signal that occurs when an object is moving, was first discovered by Christian Doppler. It applies to all propagating waves and is particularly useful for radars. This Doppler shift results from the fact that the frequency of a signal received by an observer will depend upon whether the source of that signal is stationary, moving toward, or moving away from the observer. For radar applications, the "source" of the signal is the radar wave reflected by the target. If the target is moving away from the radar, the frequency of the reflected signal will be lower than the originally transmitted frequency. Conversely, if the object is moving toward the radar the frequency will be higher. Additionally, the magnitude of the signal frequency shift is directly proportional to the radial velocity between the object and the radar. Only objects that are stationary or moving perfectly tangentially to the radar wave will not produce a Doppler shift.

The development of high-performance processing capability, along with innovative computational techniques tailored to extract desired information from the massive amounts of data available, has provided desired radar enhancements, particularly for defense capabilities.

2. TYPES OF RADAR SYSTEMS

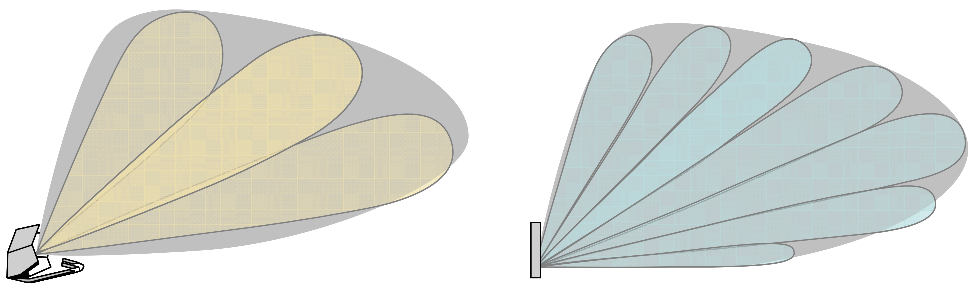
Primary Surveillance Radar

Air defense radars typically operate in what is termed a “Primary Surveillance” mode. When operated in that manner they are referred to as a “Primary Surveillance Radar” (PSR). A PSR will send out rf waves (radar energy) focused by the antenna to provide an “illuminated” volumetric region of coverage. For a radar with a single transmitting element, the characteristics of this volume of coverage will be governed primarily by the shape of the antenna and whether or not the antenna can be rotated about one or two axes.

Figure 3 illustrated a radar coverage pattern where the antenna has been shaped to produce an illuminated area that is broad in altitude and radial distance (range) but rather narrow in width in terms of azimuth angle coverage. This type of radar is generally rotated about a vertical axis to extend the volume of coverage. The angle of rotation may be as little as a few degrees to observe a small sector or up to 360 degrees to cover the entire airspace surrounding the radar. Alternatively, the antenna may oscillate back and forth over a small angle to cover only a sector of airspace. Systems of this type able to rotate a full 360 degrees can often be observed in use around airports.

Radars of the type illustrated in Figure 3 are often referred to as 2-D radars since they are able to determine the position of an aircraft in terms of range and bearing angle (angular position of the aircraft with respect to north) but are unable to determine the height at which the airplane is above the surface of the earth. In contrast, most radars designed to inherently determine aircraft range, bearing, and altitude employ multiple beams. Radars able to determine all three aircraft parameters are typically referred to as being three-dimensional (3-D) radars. Figure 9 illustrates two different types of multibeam 3-D radars. The first employs several “stacked” transmit units to produce overlapping illumination lobes. Similar to the 2-D radar illustrated in Figure 2, the entire antenna would be rotated about a vertical axis to sweep the illuminated area over the volume of airspace to be covered.

The second type of 3-D radar is known as a phased-array radar. In a phased-array radar, hundreds to thousands of small transmitters and receivers make up the face of the antenna. Radar beam patterns are formed by precisely adjusting (shifting) the phase angle of the signal sent to each transmit element. Employing a similar technique, the receive beam can also be “electronically steered” over an area to cover a specific volume of airspace. Mechanical steering can also be employed to increase the "field of regard" for a phased-array radar.



a. Stacked Beam b Phased Array

Figure 9. Two common types of 3-D radar

Phased-array radars also have side lobes. Multiple side lobes can exist in both the vertical and azimuth directions with respect to the axis of a main beam lobe. In a well-designed radar system, the power level of the side lobes will be significantly below that of the main lobe. Figure 10 illustrates the first elevation side lobe for the fifth beam of a planar phased-array radar.

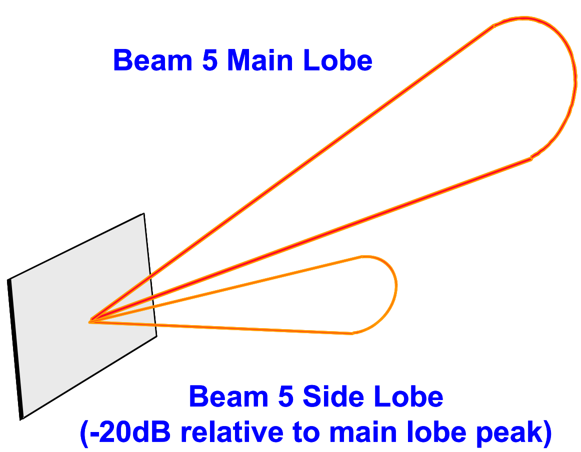


Figure 10. Notional elevation side lobe for fifth beam of the Figure 9b phased-array radar

Secondary Surveillance Radar

Secondary Surveillance Radar (SSR) is an "interactive" radar in that it requires the cooperation of the target aircraft. SSR traces its origins to the Identification Friend or

Foe (IFF) systems first developed during World War II to help air defense personnel to clearly distinguish between friendly and hostile airplanes. SSR systems are sometimes referred to as "beacon tracking" systems.

An SSR operates by sending out a coded signal (interrogation) that is received by a transponder system on an aircraft. The airplane's transponder system translates the interrogation and responds by transmitting a coded signal back to the radar. This coded signal will contain identification information about the aircraft and other data such as its flight altitude. The frequencies of the interrogation and response are different, and both are different from the primary radar frequency so that the signals do not interfere with each other. The operating frequencies, signal strength, message format, and other key parameters influencing the performance of transponders are defined by published standards [3].

A major advantage of SSR is that the return from the aircraft transponder is much stronger than the typical primary (skin) radar return and is generally unaffected by clutter sources that can affect the primary radar return. This is because the SSR system does not depend upon the "reflection" of its interrogation message. Instead, it receives a different signal actually broadcast by the aircraft. Thus, wave propagation losses in each direction are minimized. This in turn allows a much smaller antenna to be employed for SSR. Figure 11 illustrates both the PSR and SSR antennas for the United Kingdom (UK) Watchman series of Air Traffic Control (ATC) radar.

A disadvantage of the SSR is that the aircraft must have a functioning transponder. Not all aircraft are required to have transponders. Additionally, even for transponder-equipped airplanes, if the transponder fails or is turned off, the SSR will not be able to track the airplane. Under these circumstances, only a primary surveillance radar will be able to detect or track the aircraft.

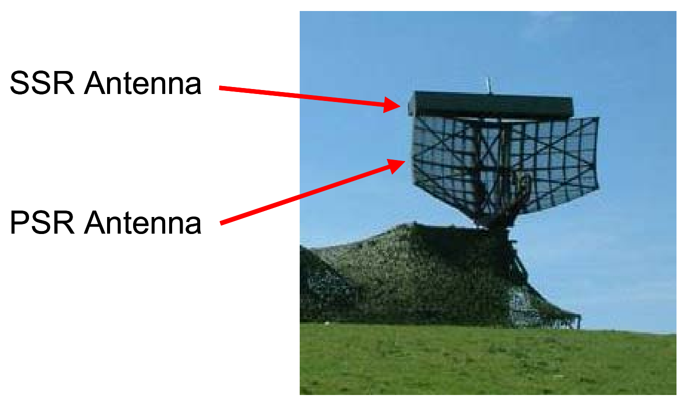


Figure 11. PSR and SSR antennas of the UK Watchman ATC radar

Missile Early Warning Radar

There are two fixed-site missile Early Warning Radars (EWR) within the continental United States. One is located at Cape Cod Air Force Station (AFS), MA. The other, an upgraded version, is located at Beale Air Force Base (AFB), CA. These two fixed-site, ground-based radars are large phased-array systems that are housed in a three-sided 32 m high building (Figure 12). The radars have two distinct radiating antennas, each capable of covering a 120-degree sector. Each antenna can generate a narrow (2.2 degrees) primary radar beam that can be electronically steered between elevation angles ranging from 3 to 85 degrees above the horizontal over the entire 120-degree field of view. These radars have a maximum range in excess of 5000 km. The far-field region for the primary radar beam begins approximately 439 m from the face of the radar.

Figure 12. Upgraded Early Warning Radar at Beale AFB, CA

Table 3 provides the elevation of the lower edge (-3 dB power level) of the primary beam of an EWR as a function of distance from the radar referenced to the center of the array face. The effect of a 3-degree upward angle in conjunction with the narrow width of the beam produces a primary beam illumination pattern that is significantly above the surface of the earth, even at short distances from the radar unit.

Table 3. Approximate radar primary beam elevation for an EWR

Distance from radar (km)	Elevation of bottom of primary beam (m)	Elevation of centerline of beam (m)
5	167	263
10	338	530
15	510	799
20	687	1072
25	866	1347

Calculations employ 4/3 earth approximation to account for atmospheric refraction effects. All elevations are relative to the center of array face. Beam size based on -3 dB power level.

The early warning radars, similar to others, also have side lobes. The first side lobe forms a concentric circle about the main beam. The second and higher side lobes are similar in character to the main beam and arranged about that beam. The power density level of the first side lobe is 1/100 (-20 dB) of the power of the main lobe, whereas the power density level of the second side lobe is 1/1000 (-30dB) of main beam power density. The first and second side lobes do intercept the ground in front of the array [4]. The distance away from the radar at which this intersection will occur varies based upon how far above the horizontal the main beam is pointed.

Weather Radar

Radar can also be employed to monitor weather conditions. In the United States, the NEXRAD WSR-88D represents the current generation of ground-based weather radars. The NEXRAD network at present consists of 158 WSR-88D radars situated across the country, with a few at various overseas locations. Figure 13 illustrates the first NEXRAD WSR-88D radar, which was installed in Norman, OK, in 1988.

The phenomenology employed by a weather radar is Rayleigh scattering. Weather radars do employ Doppler but not in the same way as air defense radars. Generally, when monitoring weather conditions such as rain, hail, or snow, the Doppler frequency shift, a function of particle velocity, will be too small to measure accurately with a single pulse. Thus, weather radars such as the WSR-88D employ timed pairs of pulses. The phase-angle difference between the reflections of two sequential pulses is directly proportional to particle velocity in the direction toward or away from the radar. By combining these measurements for multiple sequential pulse pairs over broad sweep angles, the radar is able to construct a Doppler map illustrating the rain, hail, or snowfall pattern.

Figure 13. First NEXRAD WSR-88D radar, Norman, OK

3. GENERAL PRINCIPLES OF OPERATION

Use of Clutter Cells and Background Averagers

As noted previously, the term “clutter” is defined as any undesired reflected signal return that enters the radar receiver. For a primary radar seeking to track aircraft, the earth’s surface and any man-made objects on the earth’s surface are sources of clutter. Weather effects such as rain or hail can also cause clutter for an air defense radar. Modern air defense radars normally include special algorithms to attenuate the effects of such weather phenomena on tracking performance.

The level of clutter a radar may see is highly dependent on the viewing geometry of the radar in relation to the clutter sources. In general, the level of clutter will increase when the radar views a larger area of the earth's surface or of objects on the earth's surface. Clutter can occur at any angle within the radar field-of-view angle and at any range within the radar line of sight. Clutter returns can be spread in Doppler frequency due to the motion of the radar platform or motion of the source of clutter.

Traditionally, clutter for an air defense radar has been considered to be either stationary or possessing a low velocity. Cars and trucks moving on roads, trees, buildings, and even flags waving in a breeze can create this type of clutter. Stationary or nearly stationary objects result in a return signal with a fluctuating near-zero Doppler frequency shift. Since quasi-stationary objects will generally provide nearly identical radar returns from successive scans, methods have been developed to eliminate such returns from further processing and thereby reduce their influence on tracking capability.

The use of clutter "maps" and clutter cells has been one such technique commonly employed. Figure 14 provides an example of how clutter cells are employed within a radar to support target detection. This figure illustrates a portion of an area, in terms of range (radial distance) and bearing angle (angular offset from north) under observation. Such a plot is called a Plan Position Indicator (PPI) display and is one of the most commonly recognized formats for displaying radar data.

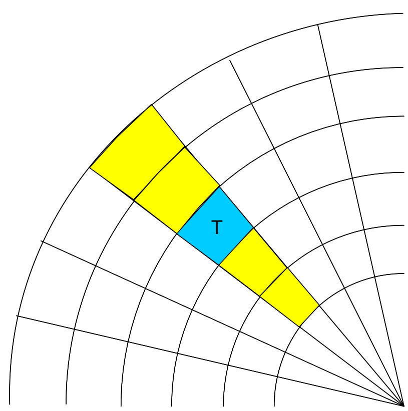


Figure 14. Clutter cell example

In this particular example the radar is seeking to determine if there is an aircraft (T) in the blue colored area. A key element in performing that task is determining whether the magnitude of the signal being reflected from that small region includes reflections from trees, buildings, and other objects (clutter) of no interest to aircraft tracking (clutter), as well as reflections from one or more aircraft. Using a grid pattern of "clutter cells," the radar compares the magnitude of reflected signals from a series of prior sweeps for that cell to the signal level now being received to determine if there has been an "above threshold" increase in reflected intensity.* The assumption here is that

* Specific target detection and tracking methods are described in greater detail in the following sections

typical clutter signals, representing reflections from stationary or nearly stationary objects, will not change significantly over a short period time and thus will produce a relatively stable history of clutter. Consequently, any sudden increase in received signal level would imply that a new object has now appeared in this cell.

This "clutter history" for a given clutter cell is also usually averaged, using weighting factors, with current clutter levels being observed in other cells in front of and behind the cell of interest. In some cases, current clutter levels in cells adjacent to the cell of interest also may be included in this weighted-averaging process. The yellow colored cells in Figure 14 provides a simplified example of cells included in the process. This weighting of clutter levels in adjacent cells enables the radar to adapt its performance to short-term variations in atmospheric wave propagation parameters and other environmental factors such as rain. Averaging of clutter cells is typically employed only when the radar is operated in a surveillance mode. When in surveillance mode, the radar will be sweeping over large volumes of airspace to determine how many aircraft are in that region and where they are located.

While clutter cells are used by radars to monitor clutter in the field of view, actual aircraft tracking employs "resolution cells." Resolution cells are generally smaller than clutter cells to enable the radar to accurately establish the actual position of an aircraft. Figure 15 illustrates the relationship between clutter cells and resolution cells. Here, the clutter cell is assumed to be 6 km in range length and 1 degree wide in azimuth angle. In this hypothetical example, each clutter cell contains 6 resolution cells 1 km in range length with the same 1 degree angular width.

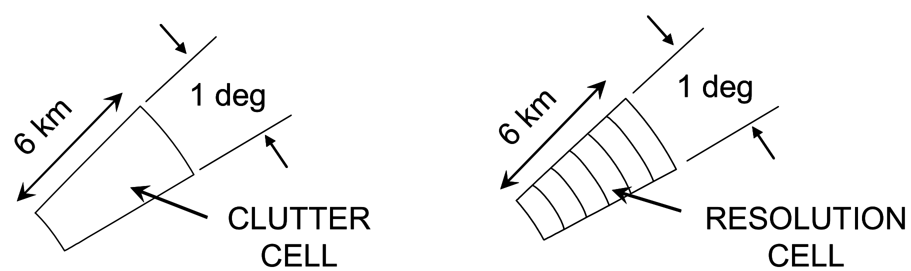


Figure 15. Relationship between clutter and resolution cells

If this hypothetical radar were a 2-D radar with an operating range from 6 to 600 km over a 360-degree field of regard, there would be 35,640 separate clutter cells that the radar processor would have to retain, and update the history of, with every sweep. If, instead, it were a three-beam radar with individual clutter maps for each beam, the number of clutter cells would increase to 106,920. As this example indicates, radar processing loads are very dependent upon the size and number of clutter cells employed for the clutter map.

As mentioned previously, the accuracy with which the radar can track the position of an aircraft depends upon the size of the resolution cell. In this example, the 2-D radar would be able to locate a non-cooperative airplane to only within a fraction of 1 km and 1 degree of its exact position depending upon signal-to-noise ratio. Additionally, it would be unable to tell if there is more than one aircraft in that small region since its tracking ability is based only on detecting an above-threshold level of signal return in a given resolution cell. Thus, a precision flight team flying in very close formation could appear to the radar as a single target without other aids such as transponder returns.

This report noted earlier that certain types of air defense radars have the capability to track individual aircraft. These are generally 3-D phase-array radars, but other arrangements are possible as well. When operated in this mode, the radar will focus an individual radar beam on the aircraft of interest much like a spotlight is used to illuminate a small area on a stage. Rather than employing "clutter maps" as described above, such target tracking systems often employ a "background averager" methodology to reduce the impacts of clutter around the target. With this technique, the radar electronics and processor systems will create a relatively small "sliding window" that is passed over the volume of airspace where the target is located. Unlike a clutter cell, these sliding windows are typically on the order of a few resolution cells in size. For the Figure 15 example, a two-cell size window could be "slid" over a few cells in front of and a few cells behind the resolution cell of interest to establish a "background" level of average clutter in that small zone. That is then used to set a clutter threshold level subsequently employed in the target tracking algorithm.

Note that a key difference between a clutter-map approach and the background-averager techniques is that a clutter map will be based on clutter levels observed over multiple sequential scans, whereas the "clutter levels" determined by a background averager are based only on observed clutter in the present scan and thus are a measure of "instantaneous" clutter surrounding the target.

Moving Target Indication/Moving Target Detection Principles.

Moving target indicator (MTI) and subsequently moving target detection (MTD) techniques have been developed to assist in the process of separating radar returns from moving objects from those produced by stationary items. A radar employing the simplest form of MTI compares two consecutive received pulses. The first pulse is stored in memory and is subsequently subtracted from the second received pulse. Consecutive return pulses from a nonmoving object will appear almost identical. Thus, subtracting one pulse from the other produces a near-zero net result. On the other hand, the Doppler shift from a moving target will have a relative change in the phase between consecutive pulses. In this case, subtracting the first pulse from the second does not yield a near-zero result. The remaining signal from the moving target is then processed to determine particular characteristics about the moving target, such as target speed and direction. This method is called filtering, where zero- (or low-) Doppler frequency signals are rejected but high-Doppler frequency signals are passed for further processing. There are alternative MTI filters that process more than two pulses, but in general they are limited to five pulses or fewer.

While MTI filters cancel the stationary land clutter, they do not provide good performance against moving clutter like rain. They also do not provide an indication of the moving target's radial velocity. Such performance can be obtained using banks of Doppler filters. Typical designs use cascaded filtering systems, where MTI is used to remove most of the very strong land clutter and banks of Doppler filters are used to provide improved detection in rain and improve estimates of the target's radial velocity.

With the development of digital technology in the mid-1970s, several versions of this technique were developed and implemented in laboratories. By the late-1970s, improved systems were developed and procured to replace the older radars then being used for long-range air surveillance. A similar Doppler radar approach to address the short-range air surveillance needs was also developed. This particular radar used an MTI followed by a bank of specially weighted Doppler filters to provide near-optimum detection of moving targets. It also employed a zero-Doppler filter that passed the land clutter, but used a clutter map to float the detection threshold just above the land clutter return. This clutter-map technique prevented the land clutter from being detected, but provided "super clutter visibility," the ability to detect stronger aircraft returns over areas of weak stationary land clutter. This enhanced radar-processing technique was subsequently called a "Moving Target Detector" (MTD) method. With the increased use of digital hardware, modern radar signal processing could now create near-optimum Doppler filters directly.

Doppler filters do have drawbacks and limitations. For instance, Doppler filters also have side lobes analogous to the range side lobes in pulse compression waveforms. Most current air defense radars are designed to use a low-Doppler side lobe weighting such that the Doppler side lobes of one aircraft are below the noise level and do not inhibit the detection of another aircraft in the same range cell. However, since the clutter models used in the design and procurement of these radars did not provide any strong moving-clutter sources, the Doppler side lobes of some of these radar filters will be inadequate in the presence of strong moving clutter.

The output signals of the Doppler filters will still contain noise and clutter, as well as targets. The detection and track initiation process is started when a detection threshold is exceeded by one of the output signals. Since a radar has limited resources for performing the detection process, it is desirable to limit the tracking processes initiated by noise and clutter (false alarms) while allowing all target signals to cross the detection threshold. Modern radars are designed with resources to handle a limited number of false alarms and make use of processing that tries to float the detection threshold just above the noise and clutter, but low enough to detect the presence of an aircraft target. This processing is called Constant False Alarm Rate (CFAR) processing. The specific objective of CFAR processing is to set the detection thresholds so that the radar can successfully track the most challenging targets of interest while keeping false target declarations (false alarms) due to noise and clutter at a constant but manageable rate.

The two figures of merit that are used to rate the detection ability of a radar are probability of detection (P_d) and probability of false alarm (P_{fa}). Probability of detection is the likelihood that a target is detected when a target is present. Probability of false alarm is the likelihood that a target is detected when no target is present. Note that a third option, the probability that a target is not detected when a target is present, is also possible. This is called probability of miss (P_m). Since P_m is directly related to P_d by the equation: $P_m = 1 - P_d$, only probability of detection and the probability of false alarm are required to specify CFAR performance.

In the CFAR processing scheme, a constant P_{fa} is established for the radar. Typical values for P_{fa} range from 10^{-4} (1 false alarm in 10,000 samples) to 10^{-6} (1 false alarm in 1,000,000 samples). A typical cell-averaging CFAR routine uses values from either the clutter map or the background averager to estimate the clutter and noise background. The threshold for target detection is then set at a level above the average background, based on the clutter and noise statistics, to ensure a very low probability that a background signal will cross the threshold and be declared a target. This processing does presume that all the received signal values have the same noise and clutter statistics as the cell under test and that the values used to determine the threshold level do not contain a target.

Target Declaration and Tracking

Once a detection threshold is crossed, the detection and track initiation process is started. This involves the estimation of the detected signal's range, azimuth, height, Doppler velocity, and other features. This information is passed to a tracker as a target file and the tracker prepares a filter to correlate this return with future returns to confirm the presence of a valid target. Once a track has been established, the tracker can predict the expected location of the target during the next scheduled beam in the target's direction and even instruct the radar to lower the detection threshold at the expected range, azimuth, and elevation to provide a higher probability of detection.

The trackers used in modern air defense radars have a large, but still limited, target-handling capability. Furthermore, multiple detections in the same range-azimuth-elevation volume create problems with track integrity. Therefore, it is important to limit the number and frequency of false alarms that are passed to the tracker. On the other hand, the most important criterion for air defense radar systems is the ability to provide an acceptable probability of detection, track initiation, and track maintenance for all targets within a certain range and within a specific velocity window. If a new clutter source is created that cannot be controlled by the radar's filtering and CFAR processing, target detection, track initiation, and track maintenance will be severely impaired in the vicinity of that clutter source. Maintaining a low false-alarm rate at the expense of sacrificing detection and tracking performance is not an acceptable option for air defense radars.

4. CHARACTERISTICS OF WIND TURBINES APPLICABLE TO RADARS

Modern SOA "utility-class" wind turbines consist of three major elements, as shown in Figure 16. The actual power-generating unit is located in a nacelle mounted at the top of a vertical column. Most columns today are tapered hollow cylindrical structures fabricated from steel. The height of the tower is, at times, adapted to the specific site conditions where the turbine is to be located. Increasing tower height can position the turbine blades in more favorable wind conditions but conversely can increase construction costs. Table 1 provides representative tower heights for some common SOA wind turbines. The towers of the wind turbines tested at Fenner, NY, were approximately 113 m tall. From the perspective of a radar, the tower will appear as a stationary reflector with no Doppler.

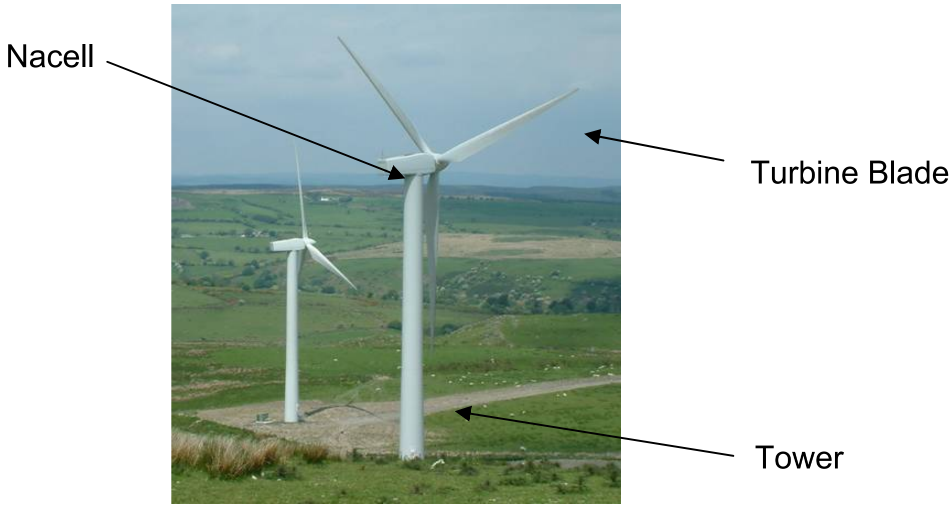


Figure 16. Picture of SOA wind turbines located in Wales, UK

The nacelle houses the power generator. For the wind turbines at Fenner, NY, the nacelle is approximately 10 m long, 4 m wide, and 3 m high. In SOA turbines, the nacelle can rotate a full 360 degrees to enable the turbine blades to face into the wind and provide maximum efficiency. Rotation rates for the nacelle tend to be relatively low. Thus the nacelle will appear to the radar as a virtually stationary object even when rotating. The nacelle housing may be fabricated from a metal or glass-reinforced plastic (GRP) to reduce its weight. Materials such as GRP can be partially transparent to rf waves. This means that some of the radar energy striking the nacelle surface can be transmitted to and reflected by the components within the nacelle. Since the majority of these internal components will also be nearly stationary (moving only when the nacelle rotates) these internal reflections should have only a second-order impact with little apparent Doppler.

The turbine blades are large, aerodynamically shaped structures that operate on the same principle as the wing of an airplane. In accordance with Bernoulli's Law, the flow of air over the surface of the turbine blade creates a pressure differential due to differences in flow path length. This pressure differential creates a net force which, in the case of the turbine blades, causes them to rotate. In SOA turbines, the blade angle of attack is usually computer controlled to maximize power production while maintaining blade rotation rates within a relatively narrow range.

Typical SOA turbine blades are fabricated using GRP and can include surface-mounted metal inserts and internal wiring for lightning protection as well as internal damping systems to control blade vibration. Again, due to the partial transparency of GRP, the internal elements within the blade can serve as secondary reflection sources for radar waves.

Most SOA turbines, including those tested at Fenner, NY, are "upwind" designs. In this arrangement, the nacelle rotates so that the blades always remain on the windward side of the tower, thus providing the blades an undisturbed flow of air. As indicated in Table 1, blade rotation rates generally fall within a speed range of approximately 10 to 20 rpm. For the two GE systems listed in Table 1, tip velocities fall in the range of 40 to 80 m/s (78 to 158 knots). Faster rotation rates, and thus tip velocities, are generally avoided to limit centripetal acceleration forces and to minimize generation of acoustic noise.

The significant physical size of the turbine blades results in a substantial RCS target irrespective of whether the blades are viewed face on or edge on by a radar. The tip velocities for these blades fall within a speed range applicable to aircraft. Consequently, the turbine blades will appear to a radar as a "moving" target of significant size if they are within the radar line of sight. The following section provides specific technical data on the RCS and Doppler characteristics for a 1.5 MW wind turbine based on field testing conducted at Fenner, NY, in May 2006.

DOD-Sponsored Field Testing of an SOA Wind Turbine

The first comprehensive effort to measure the RCS and Doppler characteristics of an SOA wind turbine reported in the literature [5] was performed by QinetiQ, a research organization in the UK. Sponsored by the UK Department of Trade and Industry, QinetiQ performed analytic modeling, compact range (scale model) tests, and actual field measurements of SOA turbines under that effort. QinetiQ's results documented that SOA wind turbines possess a significant RCS signature and create Doppler frequency shifts that will impact the ability of a radar to distinguish them from actual aircraft.

While this report provided important insights, the field test data were taken at only a single frequency, 3.0 GHz (S-band), with only the upper portion of the tower in the line of sight and at just one look-up angle. It also did not measure behavior when two or more turbines were in the line of sight to determine whether or not effects added in a linear manner. Instead, QinetiQ employed compact range testing and analytic models to evaluate some of these other factors. However, it is well recognized that compact range testing is very difficult to perform accurately for such large structures due to the difficulty in replicating fine details at the extremely large scaling factors that are required. Thus, their ability to predict with confidence behavior for other commonly employed radar bands is limited. Finally, all the QinetiQ data were only available in the form of charts and tables. This format is useful in describing behavior but inadequate as a source of data to directly insert into radar performance models.

Consequently, the Department, as part of this study, undertook an effort to create a digital database of actual radar signatures for an SOA wind turbine for all of the common radar bands. This testing was performed using the Air Force Research Laboratory's (AFRL) Mobile Diagnostic Laboratory (MDL) (Figure 17). The MDL is an SOA radar signature measurement and characterization van. It has been in use since 1997 to measure the radar reflectivity of aircraft (B-2, F/A-22) and, recently, to characterize the Space Shuttle Orbiter Discovery for susceptibility to radar interference prior to returning to space. It is currently certified to perform radar measurements to the most stringent national standards, ANSI-Z-540-1994-1.

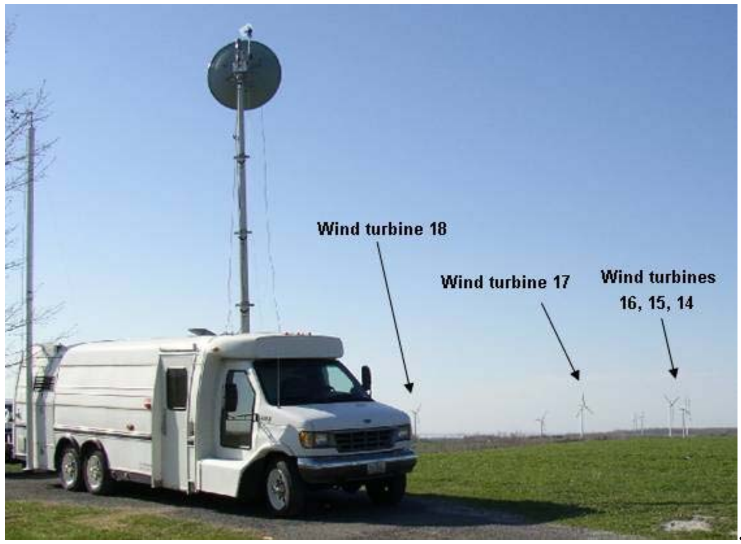


Figure 17. AFRL Mobile Diagnostics Laboratory measuring wind turbines at Fenner, NY

The wind farm at Fenner, NY, was selected for the testing site because it contained 20 modern GE 1.5 MW wind turbines, was located in close proximity to the AFRL Rome Research Site, included both locally flat and rolling terrain combinations typical of many proposed U.S. wind farms, and had co-located GE personnel. The cooperation of GE in providing access to turbine operating data during the test period was vital to the success of the measurement campaign and is gratefully acknowledged. Figure 18 provides a map of the overall layout of the wind farm at Fenner, NY, with red circles employed to indicate the turbines measured during the testing.

RCS and Doppler characteristics were obtained for a total of 10 different wind turbines tested during the 10-day test window from 29 April 2006 through 9 May 2006. A total of 479 individual calibrated measurements of turbines at L-, S-, C-, and X-bands* for both horizontal and vertical polarization were obtained. Figure 19 provides a graphical representation of the data obtained as a function of the approximate radar aspect angle to the axis of the turbine and radar frequency band (L-band: blue, S-band: yellow, C-band: green, X-band: orange).

The test procedures, samples of test data, and calibration methodology are documented in a report [6]. The full data set, in a digital format directly employable in radar analysis routines, has been made available to U.S. radar contractors and government-sponsored researchers.

* The test frequencies used for these bands were 1.3 GHz, 3.3 GHz, 6.8 GHz and 9.7 GHz, respectively

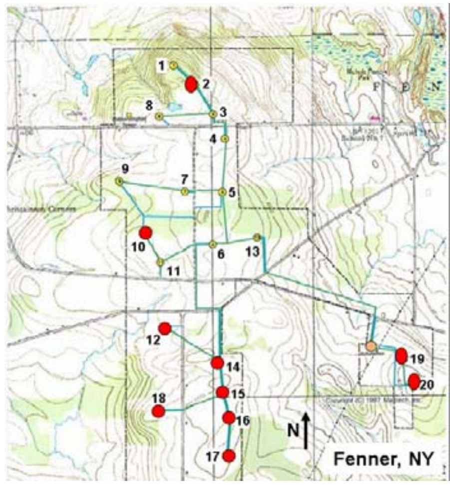
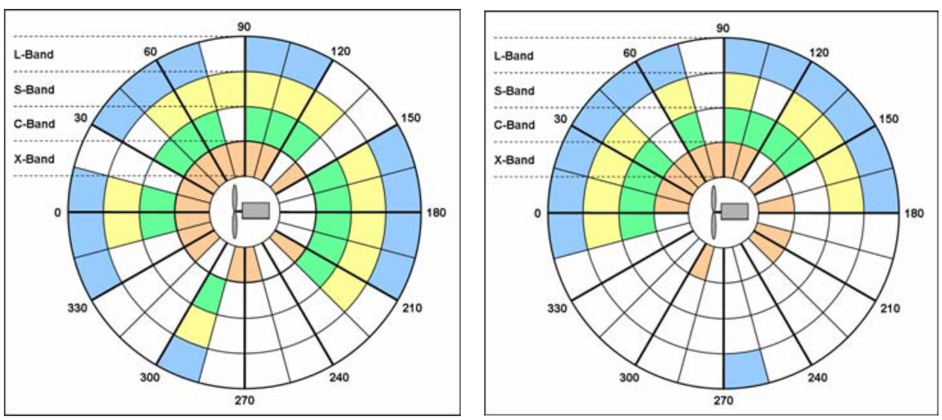


Figure 18. Layout of the wind farm at Fenner, NY, and locations of the turbines tested

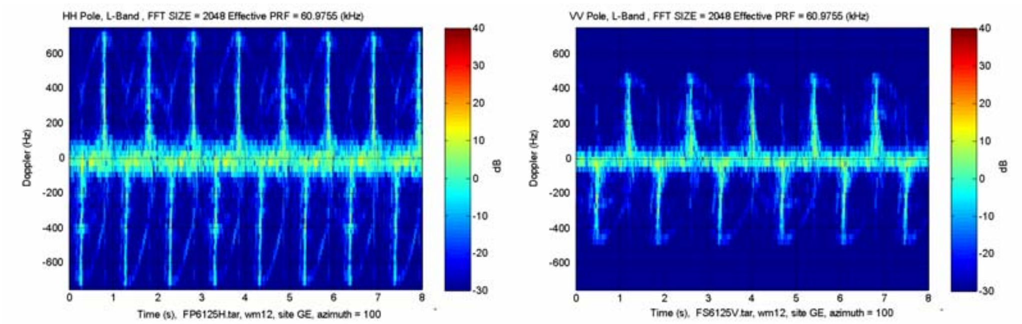


Vertical Polarization　　　　　Horizontal Polarization

Figure 19. Graphical representation of data obtained during field tests at Fenner, NY

Figure 20 provides one example of the actual measured Doppler characteristics for one of these turbines. These particular results were obtained at L-band, observing the turbine blades almost edge on. Each positive peak represents the Doppler behavior as each blade rotates into the line of sight while moving toward the top of its arc of rotation. The negative peak that follows is produced by the change in Doppler shift as the blade passes below the center of rotation and begins to move away from the radar.

Although difficult to see in this illustration, there is also a second, fainter return at twice the apparent maximum Doppler shift. This signifies a “multi-bounce” reflection of the radar wave. Multi-bounce of this nature occurs when the radar wave is reflected off two different surfaces with relative velocity to one another before it returns to the radar receiver. In the case of wind turbines, multi-bounce can occur, for example, when a radar wave is reflected by the turbine blade, then the turbine tower, and then again by the blade before returning to the radar.



Horizontal Polarization Vertical Polarization

Figure 20. Example of Doppler characteristics of a wind turbine at L-band

Figures 21 and 22 provide graphical summaries of the RCS and “apparent velocities,” as deduced from Doppler-frequency shifts, for some select cases. The RCS values indicated on Figure 21 are dominated by the tower and nacelle at the lower look-up angles. However, at the larger look-up angles, where scattering from the rotating blades dominates, the RCS values are comparable to or greater than typical RCS values for aircraft. As mentioned earlier, a full summary of test results are provided in [6].

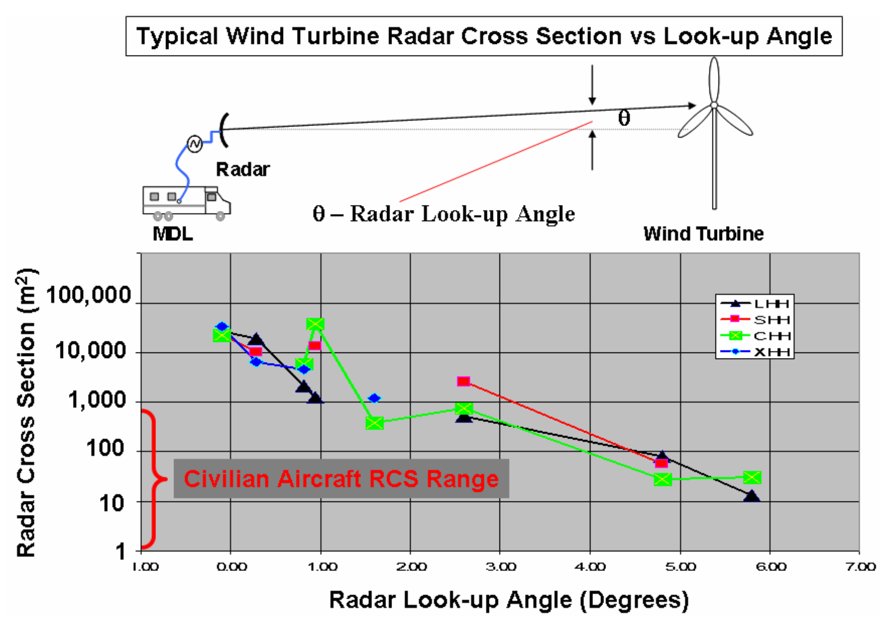


Figure 21. Graphical summary of RCS measurements for L-, C-, S-, and X-bands

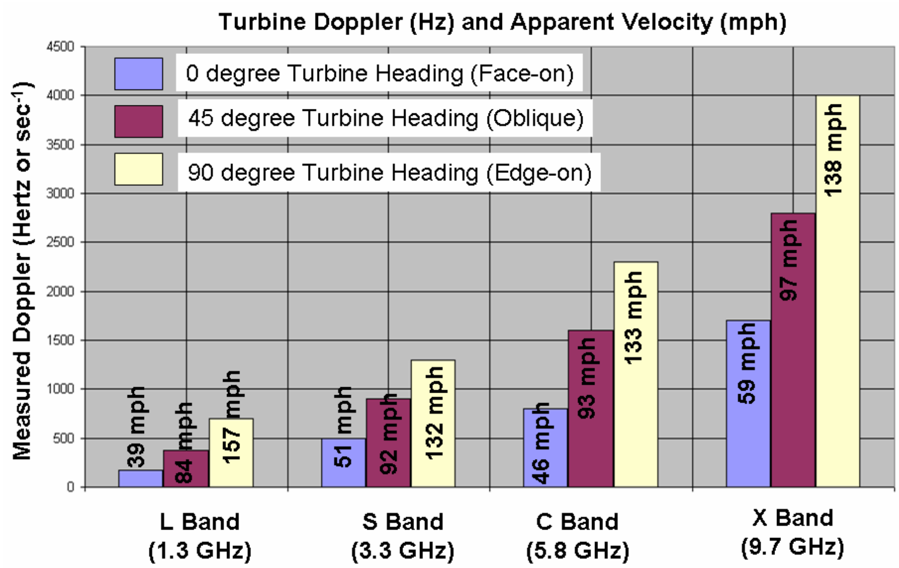


Figure 22. Doppler frequencies and derived tip velocities from measurements at L-, C-, S-, and X-band frequencies

5. OBSERVATIONS OF IMPACTS ON RADAR SYSTEMS

During the past several years there has been an increased effort to explore and document impacts that wind turbines have on operational air defense and ATC radar systems. This has been a direct result of the increase in the number of wind farms already built, the number of wind farms now being proposed for construction, and the number of wind turbines included in these wind farms, as well as the dramatic increase in their physical size. The first documented structured flight trials and analyses of these potential impacts were conducted by the UK Ministry of Defence (MoD) in 1994 [7]. This set of trials conducted ground measurements and flight trials using an ATC radar located near a small wind turbine farm. Starting in 2004 and continuing through this year, the UK MoD has sponsored an extensive series of subsequent trials employing both mobile air defense and ATC radar systems placed within a radar line of sight of several wind farms. Behavior observed during the UK tests correlates well with observations made at an operational U.S. long-range air defense radar site where wind farms have been constructed within radar line of sight.

United Kingdom Flight Trials and Analyses

The 1994 trials undertaken by the UK MoD were conducted to understand the characteristics and impacts of the radar interference observed immediately following construction of a wind farm consisting of fourteen 300 kW wind turbines located about 7 km away and in the radar line of sight of a Watchman ATC radar. The significant interference that was being observed in the radar primary surveillance mode of operation had led to a degradation in detection performance.

This was a relatively small-scale trial that involved flying a Sea King Helicopter over and around the wind turbines. This trial was structured to focus on the shadowing effect that the turbines could have on targets just above or behind the wind farm, to estimate the RCS of the turbines and to investigate the Doppler shift they would produce.

The primary conclusion of that study [7] was

> Wind turbines cause interference to primary surveillance radars. The responses appear as valid targets on the radar display. Responses cannot be inhibited using normal MTI based techniques since they are generated by a moving structure.

As a result of the trial, the MoD decided it needed to be consulted on all proposals for wind turbines closer than 60% of the maximum instrumented range of military radars. This 60% range was translated to be within 66 km (35.6 nmi) of an ATC radar and within 74 km (40 nmi) of an air defense radar.*

In 2004, the policy of carefully scrutinizing wind turbine proposals so far away from operational radars was increasingly being questioned by wind farm developers, especially in light of much less restrictive constraints imposed by other European countries. Consequently, the UK MoD commissioned additional studies to ascertain the impact of wind farms on air defense and ATC radar systems in more detail. The studies were conducted in 2004 and 2005 by the Air Command and Control Operational Evaluation Unit (Air C2 OEU)** of the Royal Air Force (RAF) Air Warfare Centre (AWC). Details of the flight trials, results, and recommendations are presented in the three RAF reports completed in 2005 [8,9,10].

The first of these trials took place over two periods, 28–29 August 2004 and 14–16 September 2004.*** Several different types of aircraft (Hawk T Mk 1A, Tucano T Mk 1, Dominie T Mk 1A, and a King Air) flew sorties over and around two wind farms within the radar line of sight of a mobile Commander AR327 - Type 101 air defense radar (Figure 23). The study observed shadowing (masking the target when directly behind the wind farm), clutter (unwanted primary radar returns), and tracking interference (inability of the system to initiate and maintain a track on a target aircraft because of the shadowing and clutter effects). Observations during the trial showed significant obscuration of primary radar returns above wind turbines. This effect was observed independent of the height of the aircraft throughout the full height range used for the trial (2000 ft - 24,000 ft above mean sea level) and represented the most significant operational effect of wind turbine farms on air defense operations. Figure 24, for example, provides a representative result from this trial. In this figure, the blue circles denote where both the primary radar return and the SSR return agreed on the position of the test aircraft. The purple diamonds denote where the location of the plane could be determined by SSR but was not detected by the primary radar. The yellow dots denote other returns by the primary radar that do not correspond to an actual aircraft.

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* The origin of the 74 km threshold is not clear since it is significantly less than the 60% maximum instrumented range of a typical air defense radar.

** Designation of this group was recently changed to Air Command and Control, Intelligence, Surveillance and Reconnaissance Operational Evaluation Unit (Air C2ISR OEU).

*** Hereafter referred to as the Fall 2004 trial

Figure 23. Commander AR327 - Type 101 air defense radar

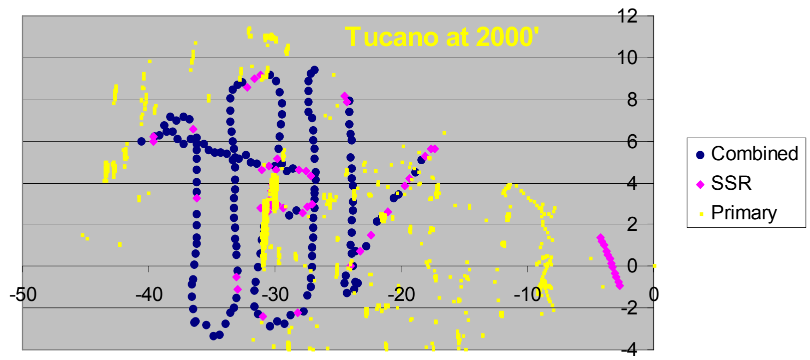

Figure 24. Example of data obtained during Fall 2004 flight trial

These results provided incontrovertible evidence that the ability to track aircraft by primary radar return alone was degraded over wind farms. In addition, it revealed that numerous false primary radar returns were occurring over the wind farm. Finally, it was found that the degradation in ability to track aircraft and the appearance of false returns occurred at all altitudes. This was an unanticipated result as the Type 101 radar is a multi-beam phased-array radar with separate beams employed to cover specific altitude regions. The specific conclusions of the report [8] on this trial included, in part:

> Overall, the Trial established that there is a significant operational impact of wind turbines in line of sight of AD (Air Defense) radars. This effect was independent of radar to turbine range and aircraft height. Where a target aircraft does not squawk SSR it is highly likely that the associated track would drift when the aircraft overflies a wind turbine farm or flies through the shadow area. Provided that the aircraft does not manoeuvre and the track is not seduced then the system should resume normal tracking as soon as primary radar returns are available. The existing MoD guideline safe-range for wind turbine farms of 74 km from AD radar when in line of sight was deemed to be irrelevant. Line of sight was assessed to be the only relevant criterion when considering objections to wind farm development.

As a result of this trial, the MoD replaced the 66 km and 74 km thresholds with a requirement for consultation on all wind development proposals within the radar line of sight of an air defense or ATC radar, regardless of distance.

The second of these studies was conducted over three separate periods, 3–4 November 2004, 23–25 November 2004, and 13–14 December 2004. This trial was very similar to the Fall 2004 trial described above but was intended to determine the effect that wind turbine farms had on ATC radars. As in the prior trial, several aircraft types (Hawk T Mk 1A, Tucano T Mk 1, Dominie T Mk 1A, Griffin HT1, and Gazelle AH Mk 1) flew sorties over and around several wind farms within the radar line of sight of a mobile Watchman ATC radar. This trial confirmed the presence of shadowing effects for the Watchman. Also, throughout the trial, clutter was displayed to the operator as a result of the rotation of the turbines blades. This displayed clutter was assessed as highly detrimental to the safe provision of air traffic services.

The third trial took place from 29 March 2005 through 8 April 2005 (Spring 2005 trial). This trial looked in greater detail at the obscuration above wind farms that was observed in the Type 101 air defense radar employed in Fall 2004 trial. Again, several different aircraft types (Hawk T Mk 1A, Tucano T Mk 1, and Dominie T Mk 1A) were flown over wind turbine farms within the radar line of sight of a Type 101 air defense radar. The results of this trial supported the theories formed as a result of the previous trials and increased understanding of the causes for the loss of detection of aircraft above wind farms.

Specifically, these tests demonstrated that the clutter produced by wind turbines directly impacted the performance of not only the “ground” (lowest elevation) lobe of the radar but also the shared aloft clutter map and the side lobe beams with line of sight to the turbines. Figure 25 illustrates a small section of the clutter cells for this radar as measured during the trial. The designation of the types of radar returns employed in this figure are identical to those employed in Figure 24.

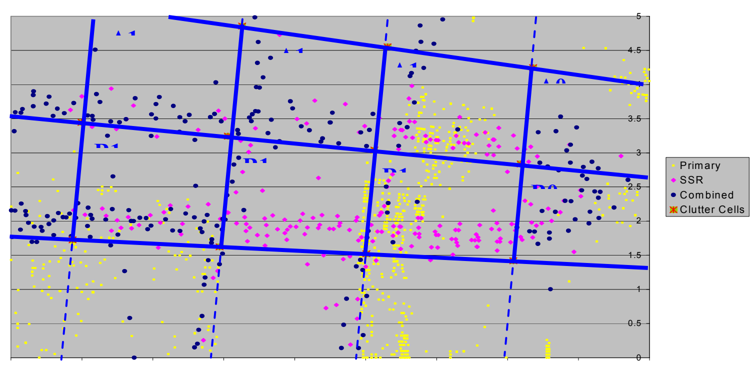

Figure 25. Sector of clutter cells superimposed on flight trial data obtained during Spring 2005 flight trial

As a result of the understanding and insights gained from these trials, the MoD and a few defense contractors conceived some potential mitigation concepts to reduce the problem of target obscuration about wind farms. Two additional studies were performed in May and June of this year to examine these mitigation concepts for 2-D radars in more detail. The concepts and trial results will be discussed in more detail in Section 6 of this report.

The results presented in the UK reports clearly demonstrate degradation in the target detection and tracking performance of the primary radar for air defense and ATC radar systems. These flight trials constitute a reasonable set of operational tests to enable identification of the probable failure mechanisms when combined (as these were) with post-trial analyses. However, since by their very nature, they can only include a limited number of flight sorties, aircraft types, variety of deceptive maneuvers employed, and other relevant factors, they do not provide a sufficiently robust statistical database to enable quantitative computations to be performed in terms of actual reduction in probability of detection, increase in probability of loss of track, and increase in probability of false alarms. Only analytic tools able to incorporate wind turbine behavior as part of their input can accomplish that task. Such tools are currently unavailable.

Observations of Wind Turbine Impacts on U.S. Operational Radars

The testing described in the preceding section involved only UK radar systems. Those tests demonstrated that wind farms would disrupt the ability to track aircraft using only primary radar returns through two distinct phenomena. The first was that the presence of a number of turbines within a limited zone would produce shadowing due to diffraction effects. This is expected based on well-established physics principles. The second disruption was due to increasing clutter levels, which adversely impacted the clutter cell threshold levels and background average performance in ways that inhibited the ability of the radar to distinguish aircraft from that clutter. From a behavioral perspective, the UK systems operate on the same basic principles as U.S. air defense and ATC radars. Thus, it would be reasonable to expect that similar performance degradation would occur for U.S. systems.

There have been two limited opportunities where DOD has been able to obtain some data from testing of operational U.S. long-range air defense radars to investigate this question. These were at King Mountain, TX, in 2002 and Tyler, MN, in 2004. Results from both of these are described in the following sections.

Testing Performed at King Mountain, TX

King Mountain, TX, provided a fledgling opportunity for a U.S. radar optimization team to explore performance of an air defense long-range radar before and after construction of a wind farm within the radar line of sight. Upon learning that a very large wind farm was proposed for construction within the radar line of sight of the Air Route Surveillance Radar-4 (ARSR-4) radar located at King Mountain, TX, a joint team from the USAF 84th Radar Evaluation Squadron (84th RADES) and the Federal Aviation Administration (FAA) conducted a very limited number of flight tests before and after partial construction of the wind farm. The ARSR-4 is a modern long-range radar with sophisticated clutter-control automation.

The wind farm proposed for construction was to consist of 214 1.3 MW turbines arranged in several nearly linear groups at distances running from 7 to 20 nmi from the radar over an azimuth sector spanning from 80 to 180 degrees with respect to north. Figure 26 provides a topographical view of the relative locations of those turbines with respect to the King Mountain radar. Approximately 80 of the 214 proposed turbines had been installed at the time that the second set of flight tests was performed.

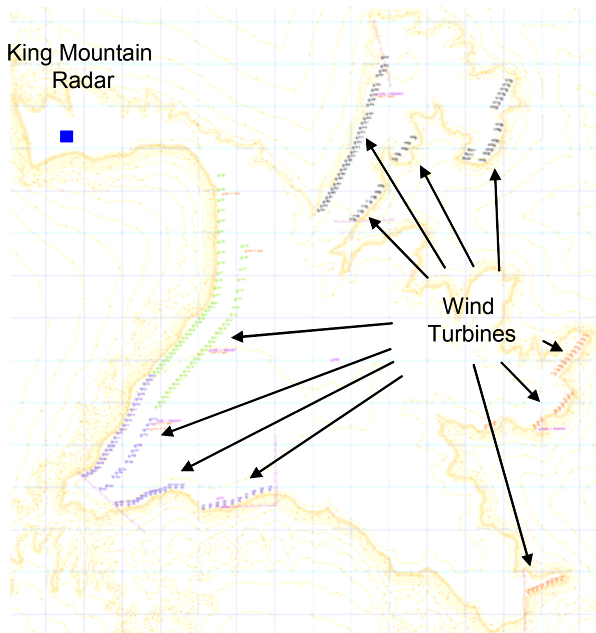

Figure 26. Location of wind turbines with respect to ARSR-4 radar at King Mountain

The U.S. team decided to employ tangential flight paths 50 nmi and 175 nmi away from the radar. Thus, the test aircraft were 30 to 155 nmi away from the turbine closest to the flight paths. These flight paths had been selected because the team had anticipated that the primary impact of the wind turbines would be shadowing and that this effect would extend a considerable distance beyond the turbines.

At the time of this "first of its kind" U.S. field test, the U.S. team was not aware of the 1994 flight trials that had been conducted by the UK MoD. Thus, they were not able to benefit from the insights provided by the UK data or to incorporate lessons learned during the UK tests in the development of their plans. The unfortunate consequence was that the very few dedicated flight trials they had funding to perform were too distant from the turbines to assess actual impacts. As indicated in Figure 6 and demonstrated in the 2004 and 2005 UK flight trials, shadowing is an effect that is localized to the vicinity around a wind farm. Additionally, the UK flight trials revealed that the predominant impact of a wind farm is to the increase clutter levels in the clutter cells around their location, thereby artificially raising detection and tracking thresholds as well as producing false target returns. By their very nature, the distant tangential flight paths employed in the King Mountain tests did not result in the aircraft flying even near those clutter cells containing the wind turbines and thus would never reveal this type of impact.

Not surprisingly, these shortfalls in the testing methodology employed at King Mountain led the team to erroneously conclude that wind turbines in the radar line of sight would not adversely impact radar performance [11]. In actuality, the most that might be concluded from those tests was that wind farm impacts on the ability of a radar to track objects at significant distances beyond the wind farm are slight. Results obtained from flight testing at Tyler, MN, would, however, lead to different conclusions regarding impacts of wind farms on radar performance.

Testing Performed at Tyler, MN

In April 2004, the 84th RADES and the FAA performed a radar evaluation and optimization of the ARSR-2 radar at Tyler, MN [12]. Upon arriving at the site, the team discovered that several hundred wind turbines had been built within a 30 nmi radius along a ridge line running approximately North-West (NW) to South-East (SE). The Tyler ARSR-2 is also located on this ridge line. Thus the wind farm straddled the radar. The closest turbine was approximately 0.75 nmi from the radar. Figure 27 is a picture of a portion of that wind farm taken from the platform where the radar is mounted. Figure 28 provides a topographical view of the relative locations of the majority of the turbines with respect to the Tyler radar.

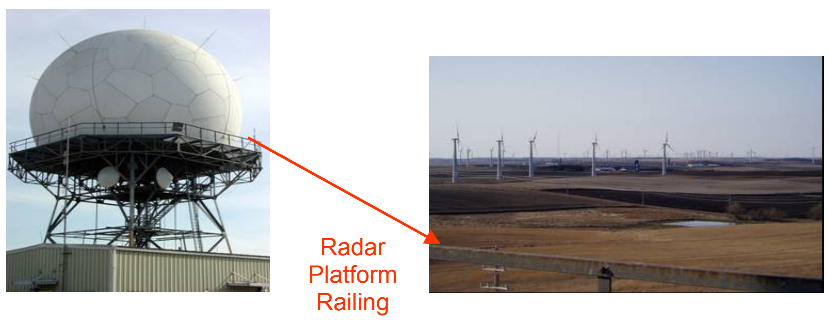

Figure 27. Picture of wind turbines and ARSR-2 radar at Tyler, MN

During the radar evaluation and optimization process, the team found that significant “constraints” had to be put in place in the radar to compensate for the elevated clutter levels created by the wind turbines. The constraints employed required that a target was not declared unless a predefined number of sequential positive returns had been observed. This is also known as a runlength discriminator. When employed, a typical constraint number is on the order of ten to sixteen sequential returns. The Tyler radar constraint had to be set at 21 for ranges from 0 to 15 nmi and at 18 for distances from 15 to 25 nmi to retain some useful capability. Use of such high runlength discriminators severely degrades radar performance; in particular, the ability to track low RCS targets.

A few dedicated flights were conducted after the radar had been optimized to evaluate its performance. One flight path used in these tests was approximately in the North-North-East direction and thus at an offset angle of approximately 70 degrees from the axis of the wind farm. Track 5 in Figure 29 demonstrates the degraded performance of the radar on April 20, 2004, when unfavorable weather conditions existed. The green segments of this track denote the portions of that flight track where the position of the aircraft determined from the primary radar return matched the position given by the SSR system (beacon). The red portions of that track indicate where primary radar return was lost and aircraft position could only be determined by beacon.

Figure 28. Location of wind turbines with respect to ARSR-2 radar at Tyler

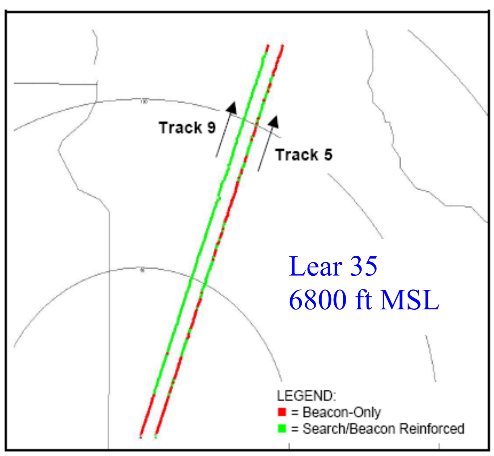

Figure 29. Tracking performance of ARSR-2 radar over wind farm at Tyler, MN

In contrast, Track 9, flown on April 21, 2004, when there were no unfavorable weather conditions, demonstrates a more typical level of performance expected for such an air defense radar. There is a small segment of lost track capability for Track 9 when the aircraft is very close to the radar. This track loss was attributable to the imposed constraints.

The clutter impacts observed at Tyler, MN, are consistent with the behavior observed in the multiple flight trials conducted by the UK in 2004 and 2005. Specifically, the radar experienced elevated clutter levels in the NW and SE directions corresponding to the locations of the wind turbines. Since the Tyler radar is an operational radar, constraints, desensitizing the radar, needed to be imposed to retain a degree of acceptable functionality.

The Tyler flight tests also revealed a collateral impact when constraints of such magnitude are imposed to accommodate wind farm induced clutter for at least this particular radar. Specifically, aircraft tracking capability in the presence of adverse weather conditions will be degraded even for flight paths not along the axis of the wind farm. This indicates that remedial measures employed to mitigate one challenge can create other forms of degradation.

Other Observations About U.S. Radar Systems

It has been noted by some individuals that a number of other U.S. radar systems have wind farms within their radar line of sight yet there are no "problems" being reported for them. As such, the question is raised as to why some air defense radars are so prone to this and others are not.

In point of fact, those other radars with line of sight to large wind farms are generally ATC radars. Two other radars sometimes mentioned in this context are space surveillance radars employed to monitor objects in space. ATC radars can rely on both primary radar returns and SSR (beacon) returns to ensure safe airspace operations. As Figure 29 and the UK flight trials demonstrates, the presence of a wind farm does not appear to significantly affect the performance of SSR systems. This is not surprising since SSR systems are actually two-way communications systems between the "tracking radar" and the aircraft. As described earlier, the SSR unit sends out an "interrogation" pulse to the aircraft. The aircraft transponder then replies with its own independent signal to the SSR. Note that even the UK flight trials relied on SSR returns to document actual aircraft positions during the tests.

The DOD has obtained proprietary information for at least one U.S. ATC radar that provides documentary evidence that a large wind farm in the radar line of sight does cause significant loss of primary radar tracking capability for aircraft flying over that wind farm. Unfortunately, due to the proprietary nature of that data, the Department is legally prohibited from publicly sharing that information.

Comments Regarding Air Traffic Control and Weather Radars

Air defense and missile warning radars must be able to unambiguously detect and track all objects of interest by primary radar alone. Thus, these detection and tracking capabilities must be maintained whether or not the object being observed is "cooperative" in sense of providing SSR signals. This requirement is distinctly different than the primary radar tracking capability that may be required for an ATC radar. ATC primary radars are only one element of a system employed to ensure safe use of the U.S. airspace. Other elements of this system include use of SSR, flight rules, and published approach and departure procedures, to name a few.

The Department is but one of a number of users of U.S. airspace in this regard, sharing that use with others such as the commercial and general aviation sectors. The FAA has the responsibility to provide for and promote the safe and efficient use of U.S.

airspace. Since ATC radars are an integral contributor to that overarching mission, the Department does not believe it would be appropriate to independently evaluate how the presence of wind farms in the radar line of sight of those ATC radar could influence the air traffic management system. Instead, the Department is prepared, as one of multiple stakeholders, to work with the FAA in such evaluations and, as appropriate, develop mitigation approaches that would be mutually applicable to air defense and ATC radars.

In a similar manner, the National Weather Service of the National Oceanic and Atmospheric Administration (NOAA/NWS) has the primary responsibility to provide weather forecasts for the United States. These weather forecasts do, in part, depend upon proper operation of the WSR-88D (NEXRAD) system of weather radars. The Atmospheric Radar Research Center at Oklahoma University (http://arrl.ou.edu) is currently conducting studies to examine potential impacts of wind turbines on ground-based weather radars for NOAA/NWS. As such, the Department defers to NOAA/NWS regarding assessment of potential impacts of wind turbines on ground-based weather radars. The Department, as a consumer of their product, is prepared to assist NOAA/NWS in development of mitigation measures where they have mutual applicability for air defense and missile warning radars.

6. POTENTIAL MITIGATION APPROACHES

The following sections will describe a number of potential mitigation approaches that could be employed to reduce or eliminate the adverse impacts wind turbines can have on air defense and missile warning radars. For the purposes of this section, the word "mitigation" is specifically defined to include either an approach that completely prevents any negative impact from occurring or an approach that sufficiently attenuates any negative impacts so that there is no significant influence on the capability of an air defense or missile warning radar. Additionally, it is noted that the ability to describe a technique as a potential mitigation is not equivalent to saying that this technique has been tested and verified. Significantly, only a few of the techniques described in the following sections have been proven to actually work and can be employed today. All of the others are best characterized as "works in progress" still requiring further development and field or analytic validation of effectiveness.

Line of Sight Mitigation Techniques

The performance of a radar will not be affected by objects that do not appear within its line of sight unless exceptional circumstances exist. With respect to objects projecting upward from the surface of the earth, such as wind turbines, radar line of sight is determined by four factors when there is no intervening terrain. These factors are the height of the focal point of the radar above the earth's surface, the height of the wind turbine, its distance from the radar, and how much the atmosphere will refract the radar beam. Figure 30 illustrates how these parameters interact. The yellow zone outlines the portion of the airspace that will be in the radar line of sight. Thus, the two turbines closest to the radar are in the radar line of sight. The third turbine, on the far right-hand side, is not. In fact, in colloquial terminology, this particular turbine would be described as being "below the radar."

Atmospheric refraction of the radar beam is indicated by the dashed curved line at the bottom of the yellow zone. Note that the curvature of the earth influences the line of sight. As an estimating rule (described in an earlier section of this report), radar engineers often use a "4/3rds earth" approximation to account for the effect of atmospheric refraction near the surface of the earth. When doing this, they multiply the radius of the earth by the factor 4/3 when performing the tangent line calculation to determine if an object is in a radar line of sight.

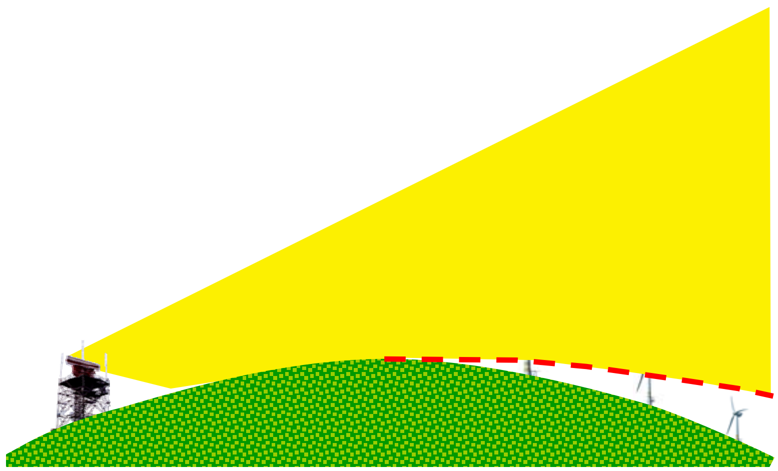

Figure 30. Illustration of "bald earth" line-of-sight mitigation approach

Figure 4 illustrated the basic geometry employed to estimate radar line of sight near the surface of the earth when using this approximation technique. Figure 31 provides an illustrative set of results that would be obtained using this method for the particular situation where the focal point of the radar is approximately 50 ft above the local elevation of the surrounding terrain. Note that in this case, a turbine where the tip of the blade at the apex of the arc of rotation is less than 300 ft above the local terrain elevation would need to be approximately 30 nmi away from the radar to be out of the radar line of sight. Turbines with lower peak elevations could be closer whereas those with blades extending higher would need to be farther away. This is a proven method of mitigation.

Figure 32 illustrates a line of sight mitigation when there is elevated terrain located between the radar and the wind turbines. This form of mitigation is sometimes called "terrain masking." Note that here only the turbine closest to the radar will be in the radar line of sight. The turbine in the middle of the drawing is no longer in the line of sight due to the "masking" effect provided by the intervening terrain. The third turbine, on the far right, is not in the line of sight due to both terrain masking and distance from the radar.

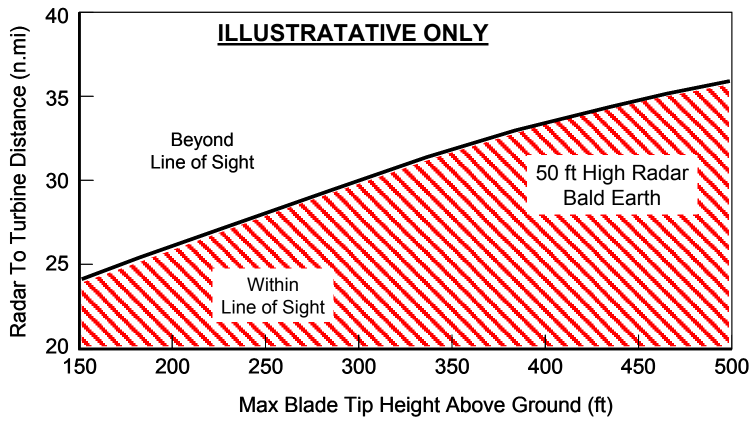

Figure 31. Illustrative results of line of sight distance offsets using a "bald earth" approach

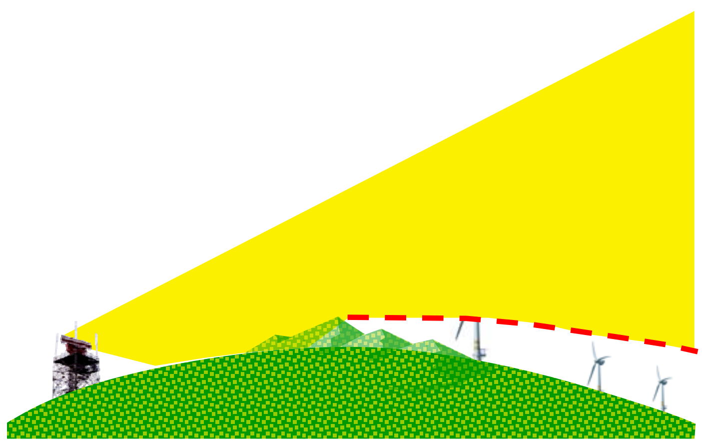

Figure 32. Illustration of "terrain masking" line of sight mitigation approach

Unlike the "bald earth" approach, there is no simple "back of the envelope" method to quickly estimate whether or not intervening elevated terrain will mask an item from a radar line of sight. In general, "beam propagation" techniques used in conjunction with terrain elevation databases must be employed to determine if this form of mitigation will apply. Figure 33 illustrates this type of analysis. This particular analysis was performed to determine if the wind turbines at Fenner, NY, would be within the radar line of sight of the research radar located at the AFRL Rome Research Site. In that case, the intervening terrain was very close to completely masking the wind turbines.

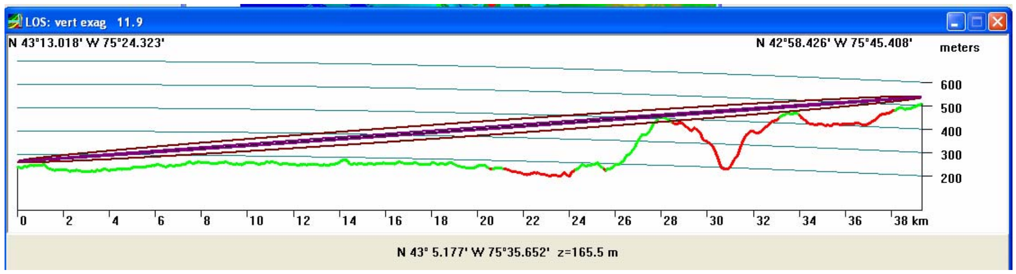

Figure 33. Illustration of "beam propagation" analysis to evaluate "terrain masking"

While not difficult to perform, these computations can be time consuming when multiple sites must be evaluated. This method is a proven mitigation technique and may be exploited, in select cases, to allow wind turbines to be constructed closer to air defense and missile warning radars than what the "bald earth" approach would permit.

"Terrain relief", a variant of the "terrain masking" mitigation approach, can be employed when the elevation of the radar is significantly greater than the elevation of the wind turbines. An example would be a radar located on a mountain ridge overlooking a valley that contained wind turbines. Those wind turbines, provided they are not located within either the main lobe or any side lobes of the radar, would not impact radar performance. Effectively, this is an alternative methodology to keep the wind turbines out of the radar line of sight. This is another effective mitigation technique that can be used today.

Returning to Figure 30, it can be noted that the middle turbine in that illustration is only partially in the line of sight of the radar. This raises the question of whether a portion of a wind turbine could be in the radar line of sight without causing significant degradation in radar performance. Analytic models able to predict the radar signature of a partially visible turbine and simulation tools capable of artificially injecting such signatures into operational radar processors would be needed to evaluate this potential mitigation concept. Software routines have been developed to predict radar signatures. These can be employed to develop appropriate models for wind turbines. The Department already has an effort underway to develop just such a model for the wind turbines tested at Fenner, NY.

Software routines also have been developed to enable aircraft radar signatures to be artificially injected into digital processors of modern operational radars. This enables assessments of the ability of that radar to detect and track aircraft under "real world" clutter and other environmental conditions. Following this paradigm, the Department has also initiated an effort to explore the feasibility of adapting such an approach to determine if representative wind turbine generated clutter could also be artificially injected. If such a methodology can be developed, it would enable air defenders to assess to what extent a wind farm proposed for construction within a radar line of sight would affect the probability of detection and the probability of false alarm for that radar. These are the critical factors air defenders must know to determine if a proposed wind farm in a radar line of sight would create an unacceptable degradation in their capabilities.

Until such models and tools are available, the potential mitigation approach of partially masking turbines must be categorized as unproven, requiring further development and validation testing.

Wind Turbine Radar Signature Suppression Concepts

The development and deployment of radar signature suppression technologies for military aircraft naturally leads to the question of whether or not a similar approach could be employed to suppress the radar signature of a wind turbine. An excellent discussion of a number of techniques that might be employed to accomplish this is available in a report prepared by Alenia Marconi Systems Limited in 2003 [13]. Thus, they are not discussed in detail here. Instead, two key points are noted.

First, as indicated in Figure 7, the RCS of an SOA utility-class wind turbine can exceed that of a long-haul wide-body commercial airliner such as the Boeing 747. The RCS of such an item would have to be reduced by 30 to 40 dB to be “relatively invisible” to most air defense and missile warning radars. This is equivalent to reductions on the order of 1/1000 to 1/10,000 of current RCS values. While lesser reductions in RCS may be beneficial, the absence of tools to enable RCS clutter values for wind farms employing suppressed signatures to be injected into radar processors means that there is no current capability to assess how effective this would be.

The second point is that such radar signature suppression methods generally require modifications to the shape of objects and use of special materials in their construction. Some of these may be relatively cost neutral for a wind farm developer. For example, increasing the angle of taper of the turbine tower will reduce its RCS and be unlikely to result in a significant change in cost. Use of a radar-absorbing material in the construction of the turbine blades, on the other hand, will significantly increase both first and life cycle costs as these materials are more expensive to procure and less weather durable than the GRP currently used.

As such, this approach ultimately becomes a cost-trade issue for the wind turbine manufacturer and the wind farm developer. Specifically, would the increase in costs to use radar suppression signature techniques counterbalance the possible increases in transmission line costs and losses resulting from locating those turbines a greater distance from an air defense or missile warning radar? Questions such as these should be addressed by the wind turbine industry and not the Department. To date, radar signature suppression techniques for SOA utility-class wind turbines have not been employed or field tested.

Thus, this potential mitigation approach must be categorized as unproven, requiring further development and validation testing.

Concepts for Radar Hardware/Software Modifications

A variety of approaches have been suggested for both hardware and software modifications to radars that would reduce their sensitivity to wind farm generated clutter. These include use of finer clutter cells, use of more and/or adaptive Doppler filters, use of special post-processor track file maintenance routines to prevent track drops, use of enhanced adaptive-detection algorithms, and use of special clutter suppression algorithms developed for other applications.

There is ongoing development work on some of these approaches being conducted by the radar industry under internal research and development efforts. In most cases, this work is focused on developing enhancements for existing products. Outputs from some of these development activities are being tested in "engineering" units, but to date none appear to have been deployed into operational units.

The Department is supporting these efforts by providing U.S. radar companies access to, and free use of, the database the Department obtained from the testing efforts conducted at Fenner, NY. In fact, this government-owned nonproprietary database was created for this specific purpose.

In May and June of this year, the UK MoD conducted independent flight trials of two proposed approaches developed for 2-D radars. Representatives from the Department were invited to, and did observe, portions of those trials. The impression of the Department's observers was that both approaches showed promise, but neither was fully successful.

Consequently, as a result of the above, it is concluded that all of the hardware and software approaches described above must still be categorized as unproven, requiring further development and validation testing.

Concepts for Gap Filler Mitigation Approaches

The underlying idea for this concept is exceptionally simple: if one radar cannot see an object due to obscuration created by a wind farm, then use a second radar that provides overlapping coverage. Figure 34 illustrates how such an arrangement would operate. The lines denote the limits of the areas beyond the blocking item where radar coverage would be inhibited. As indicated by this drawing, the radar zone of coverage for the radar on the left-hand side covers all the area blocked from the view of the radar on the right. Conversely, the radar on the right-hand side covers all the region where the view of the radar on the left has been blocked.

Coordinating two radars by software does present a number of challenges. First, a radar can locate the position of a target only within a finite level of accuracy determined by the size of the resolution cell. In the example, the resolution cells for one radar unit will never align with those of the other due to the offset positioning. Thus, inherent uncertainties are created in actual position when returns from one must be compared with returns from the other.

Second, it is unrealistic to expect that the radar beams from each unit will sweep the exact same area of interest at precisely the same moment. As such, relative target motion will always occur between the observations made by each radar. The coordination software would need to account for that as well.

If the "blocking area" is a wind farm, each radar will also experience false returns due to the rotation of the turbine blades and bleed through from the clutter map. There are no data available at present to determine if such false returns will be seen by both radars concurrently. If they are not, then the coordination software also will face the challenge of determining if the changes in observed position are due only to positional uncertainty and relative motion of the target or represent track "seductions" caused by false returns seen by one radar but not the other. This further increases the coordination challenge.

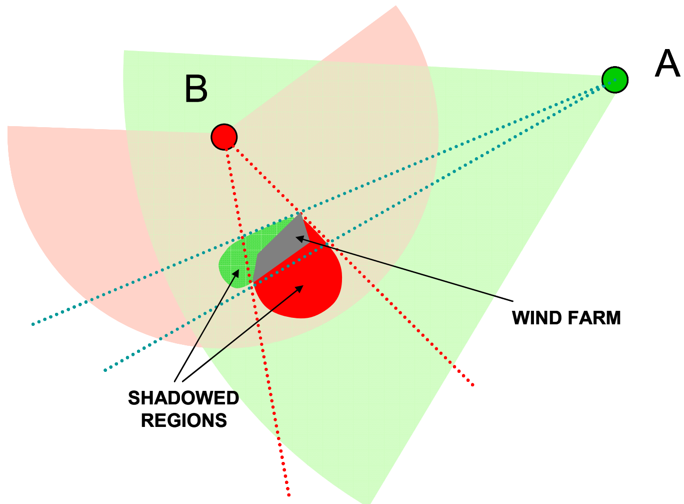

Figure 34. Overlapping radar coverage example

The Department is aware of only one study that explored such a concept in any detail [14]. This study concluded that multiple significant changes would be required to the radars that would be employed. Additional radar sensors would need to be procured, and the physical layout (shape) of that wind farm would need to be "optimized" from a radar perspective. Ultimately, the study concluded there would still be some negative impacts.

An alternate approach would be to employ a "gap filler" radar positioned within the wind farm but sufficiently high above the arcs of rotation of the turbine blades so as not to be affected by the clutter they can create. Certain types of small tactical radars developed for other applications may be suitable candidates. The use of such small tactical radars in this manner is a new concept developed during the course of this study. Analyses, including the susceptibility of such radars to clutter generated beneath them as well as the capability of the air defense system to accept the additional input, need to be performed to determine if there are merits in pursuing this concept further.

Based on the above discussions, it must be concluded that concepts that employ gap filler or supplemental radars are still immature and cannot be categorized as proven mitigations.

Testing and Verification Factors

A critical issue regarding validation of potential future mitigation approaches is how to verify their effectiveness. As noted earlier, the key performance factors for any air defense or missile warning radar are probability of detection, probability of false alarm, and probability of loss of track. By their very nature, these are statistical metrics. Accurate computation of these require numerous test cases to be examined to provide the necessary statistical reliability. Such test cases are generally analyzed using computational models with Monte Carlo techniques employed to replicate influences of variances in key parameters. However, all these models are anchored with actual test data to ensure they accurately replicate true system behavior.

With regard to wind farms, the Department has initiated efforts to develop an analytic model to replicate the RCS and Doppler characteristics of a specific SOA utility-class wind turbine. Ultimately, additional models may need to be developed to replicate other brands, styles, and sizes of wind turbines. This will ensure that wind turbine models used in analytic simulation tools will be sufficiently robust to capture the key characteristics of all current generation SOA utility-class wind turbines in an appropriate statistical manner.

The Department also has initiated efforts to explore the feasibility of creating simulations of wind farms that could be numerically injected into the processors of operational radars. These would provide important tools to assess impacts that could result from construction of future wind farms within radar line of sight of an air defense or missile warning radar.

The final issue that must be addressed is how to anchor these models and tools with test data to ensure they accurately replicate real-world behavior. The testing the Department has already performed at Fenner, NY, should be sufficient to validate that analytic RCS and Doppler models can be created for an SOA utility-class turbine. Flight trials using radars that already have wind farms within the radar line of sight can provide another critical validation tool. However, the selection of what specific site or sites that should be used for this purpose requires careful consideration.

For example, the Altamont wind farm contains a very large number of wind turbines where the overwhelming percentage are “out-of-date” designs with relatively small turbine blades. The RCS characteristics of those blades inherently will be significantly lower than current generation systems. Additionally, many of those wind turbines are mounted on relatively short tubular truss towers. Those towers will have significantly different RCS characteristics than the tapered cylindrical towers being used now. Finally, the older model turbines at Altamont rotate at higher rate than that used for more modern designs. All of these factors suggest that this particular location would not serve as the best test site to explore or verify any proven mitigation strategy.

Consequently, an effort will need to be undertaken to establish appropriate criteria for selection of test sites to conduct flight trials. Such an effort should be performed before U.S.-sponsored flight trials are attempted to ensure the results obtained will provide the data required for modeling and simulation purposes.

7. OTHER POTENTIAL IMPACTS ON DOD READINESS

This section of the report describes other areas where the presence of wind turbines or wind farms have the potential to influence Department readiness. These generally fall under the requirements associated with the Department mission to train and equip U.S. forces. The discussions in this section are specifically limited to those aspects as they pertain to Department facilities and sites within the 50 states and U.S. territories and possessions. Possible impacts at overseas locations are not included as they must be evaluated in light of existing agreements with host nations.

The Department must carry out its national security missions effectively with careful attention to the safety of the general public and Department personnel. The presence of wind turbines in the vicinity where these military missions occur has the potential to impact the effectiveness of such missions and thus military readiness.

It is important to note that while this section discusses potential areas of impact to readiness it would be inappropriate to draw sweeping or broad-based conclusions that these would occur at all facilities and sites employed by the Department. As operational requirements at different locations vary, the particular characteristic of a wind farm may present a challenge in one location but not others. Consequently, within the context of this section, potential impacts on readiness due to any particular proposed wind farm development need to be evaluated on a case-by-case basis. Where possible impacts to readiness could occur it is important to ensure that appropriate measures to mitigate risk are identified and implemented.

Finally, it should be noted that many of the potential impacts discussed in this section are similar to those that can be posed by other tall objects such as radio antennas, cell phone towers, and buildings proposed for construction in the vicinity of Department sites and facilities. The Department has developed and employed, for many years, strategies and mitigation techniques to effectively address those possible impacts. To date, the Department has not identified any specific information that would lead to the conclusion that those methods would not be similarly effective for addressing potential impacts from proposed wind farm developments as they relate to the items in this section of the report. As such, these items have been included in the report only to ensure completeness of this overall assessment.

The potential impacts to readiness are generally categorized into the following areas: 1) Overflight and Obstruction, 2) Security, 3) Signature, and 4) Environment. Potential impacts to flying safety are considered in the area of overflight where obstructions are introduced. Potential security issues during and after development are addressed near installations or where the Department conducts operations. Potential impacts related to the electromagnetic signature associated with wind turbines are evaluated. Finally, possible impacts related to the responsibilities of the Department with regard to environmental stewardship are discussed.

Overflight and Obstruction

The potential overflight obstruction hazard impact to readiness is a shared potential impact to all aviation users including the Department, commercial, business, and general aviation users. As with other large vertical construction projects, such as telecommunication towers, the Department considers the potential impacts of wind farm development on flight safety from obstructions introduced near Department airfields and in other areas used for military flight operations.

The potential impact of any tall vertical development near Department airfields is virtually identical to the risks associated with development near civilian airports such as potential interference with flight operations during take off, departure, approach and landing. In relation to flight operations away from airfields, excessive development of wind turbines in, under or adjacent to airspace, test ranges and training ranges where low-flying operations are conducted may adversely affect the altitude at which operations can be conducted. There is a potential increased risk due to the increased likelihood of encountering tall vertical structures during low altitude flight operations. The nearby location of overhead transmission lines to connect the wind turbines to the local power grid can also present a flight hazard to low altitude flight operations. The individual evaluation of any proposal considers such impacts of any specific development on a specific section of airspace. Further, the Department must consider the potential for wind farm development to obstruct or restrict military surface missions, ground maneuver operations; sea surface and sub-surface operations.

Effective management procedures already are in place to deal with questions that may arise from potential obstruction of airspace due to the proposed construction of wind turbines. As a general rule, specific Department installations are assigned management responsibilities for a section of airspace. If a proposed wind turbine is to extend more than 199 ft above local elevation, a notification of proposed construction should come through the FAA's Obstruction Evaluation / Airport, Airspace, Analysis (OE/AAA) process. The FAA will notify the managers of any affected military flying routes. The affected Services evaluate the proposal for any possible detrimental impacts to operations.

Security

In some circumstances, wind farm developments near Department facilities and sites may pose temporary or long-term security risks of various degrees. Similar to other large construction projects near Department installations, the increased level of personnel and activity during construction requires increased monitoring for security purposes. Additionally, similar to other tall vertical development, wind turbines can provide increased visual and sensor access to sensitive Department areas and activities.

The Department, as part of its normal practices, adapts its security measures in such situations. Thus wind farm development is not anticipated to create any special challenges in this regard.

Signature

As discussed in other sections of this report, a wind turbine has a unique electromagnetic "signature" that can vary based on environmental conditions. The specific signature characteristics of a given development may have potential impact on certain types of Department systems. Examples of the areas of potential impact include, among others, systems specifically designed to operate in or influence the electromagnetic spectrum such as electronic warfare activity for communications, surveillance, threat, and radar systems. Further, the Department must determine potential impacts to space launch activities and telemetry operations. The potential impact of the signature may be increased in areas where the Department conducts high fidelity developmental testing and evaluation in the electromagnetic spectrum.

Additionally, the electromagnetic signature of a given development either created by the wind turbine itself or as a result of reflection from other sources should be evaluated for potential electromagnetic interference with electronic systems routinely employed in military missions. The potential impact could be on Department installations or in areas where the Department conducts operations. This includes systems under development as well as those already fielded.

Special analyses will need to be conducted to evaluate situations where potential electromagnetic signature impacts could occur.

Environment

Military installations, testing and training facilities expend considerable effort to ensure adequate measures are being taken to conserve and protect the nation's environment and natural resources. Under the Readiness and Environmental Protection Initiative (REPI), 10 USC 2684a, many Department installations have, or are developing, encroachment and conservation buffer partnerships on lands in the vicinity of, or ecologically related to, a military installation or training/testing area. These partnerships are aimed at relieving encroachment pressure from either incompatible development and/or loss of natural habitat, which could adversely impact military operations. This program applies to installations, airspace, and coastal waters within the United States and its territories.

Where such encroachment and conservation buffer partnerships exist or are in development, proposals to develop wind farms in or adjacent to those areas should be carefully evaluated to ensure compatibility with such partnerships and related activities.

Summary of Potential Mitigation Approaches

General recommendations for mitigation of potential impact include establishment of multi-agency stakeholder groups to improve the processes used by developers and the federal, state and local governments in the proposal and evaluation phases. This will involve establishing stakeholder groups with other federal agencies that have equities in this subject area. Such interagency forums should review and evaluate existing processes and adjust those as necessary to identify and address potential impacts.

As a general rule, Department installations are assigned management responsibilities for specific sections of airspace. In many cases, proper documentation and charting of the location will provide sufficient mitigation. Methods to provide aircrew with development notices and updates to air navigation charts that are prepared and distributed expeditiously as wind power development continues to accelerate will be reviewed and revised as appropriate to mitigate the potential risks associated with overflight and obstruction.

Potential security risks identified may be mitigated through increased awareness by Department personnel during and after construction depending on the nature of the potential impact. Any unique, site-specific impact, would be addressed by the appropriate Department organization and the potentially impacted facility.

Additionally, at the regional and local installation level, community-outreach programs provide viable venues for installation commanders to work with wind farm developers to mitigate potential impacts. One successful Department initiative has been the development of "Red/ Yellow/ Green," traffic light charts to be used by both the Department and developers for discussion and dialog. These charts identify specific areas around installations where Red is employed to designate areas where a wind farm development is highly likely to impact readiness, Yellow to denote areas where collaboration is needed to avoid or mitigate impact and, Green to identify areas where there is no anticipated impact to Department readiness. It is critical to note that this approach is applicable to the topics discussed in this section but not appropriate to address impacts on air defense and missile warning radars that were discussed elsewhere in this report.

8. SUMMARY

Air Defense Radars - Shadowing

Wind turbines are physically large structures that will block the transmission of radar waves in a manner similar to tall buildings. The blockage caused by a single turbine, due to its slender shape, will be relatively small, resulting in a negligible shadow area behind that single turbine. Multiple turbines located in proximity of each other will also cause diffraction of radar waves. Decreasing the separation distance between the turbines increases the diffraction effect.

The diffraction of the radar waves will reduce the intensity of the propagating wave directly behind the turbines (see Figure 6) as well as the reflected signal from a target. This two-way reduction in signal strength will increase the difficulty in detecting and tracking targets flying at low altitude in the immediate vicinity of the wind turbines. This effect will be most pronounced for targets with a small RCS. Such targets inherently are the most challenging in all circumstances, and this added burden will result in a noticeable reduction in probability of detection for them.

Predicting the reduction in signal strength due to diffraction effects is potentially a mathematically tractable problem when it is assumed the turbine blades are stationary. This has been the basis for the "spacing algorithms" employed by a few nations. No method exists at present to accurately calculate the reduction in signal strength that will occur when the turbine blades are rotating.

Turbine blade rotation will also create false returns when attempting to detect and track targets at very low altitudes. This further complicates the situation, leading to the potential that low-RCS targets can successfully employ wind turbines to execute a "covert" approach to a high-value asset. This will compromise the ability of on-site or nearby security forces to detect such a possible attack with sufficient lead time to react. Consequently, special case-by-case analyses will be required to assess potential impacts on local air defense systems for high-value assets to determine if a nearby wind farm could compromise reaction capability. In such cases, any proposed wind farm should be located at a sufficient distance so that the on-site defense forces are able to identify any potential threat with sufficient warning time to enable them to react as required. Failure to incorporate such considerations in locating wind turbines either on site or in the nearby vicinity will degrade military readiness for this mission.

Air Defense Radars - Clutter

Modern utility-class wind turbines, due to their large size, possess a significant RCS at all common radar bands. Based on the data obtained during this study, the RCS for one particular turbine ranged from that of a "business class" airplane to a value greater than that of a long-haul, wide-body aircraft. In addition, the rotating blades of such wind turbines create Doppler shifts equivalent to the velocities of aircraft.

Since the wind turbines in a wind farm are geographically stationary and near the surface of the earth, these two effects will combine to appear as "clutter" to an air defense radar. The amount of clutter produced will increase in direct proportion to the number of turbines within the line of sight of the air defense radar. A single turbine located a reasonable distance away from an air defense radar will have minimal impact on the ability of that radar to successfully detect and track all potential targets of interest to include challenging low-RCS targets. However, a large number of wind turbines spread over a wide sector of coverage for that radar will significantly degrade the ability of that radar to perform its mission. This form of impact has been documented in numerous UK MoD-sponsored trials.

At present no tools exist to accurately determine where the transition point lies between the minimal impact created by a single turbine and the unacceptable level of degradation that will be produced by a large wind farm located in radar line of sight. The Department has initiated efforts to develop such tools. Until such tools have been developed and validated, the Department will be unable to ensure that fixed-site U.S. air defense radars are not compromised in their performance should a wind farm be constructed within the radar line of sight. Degradation in the detection and tracking ability of long-range air defense radars will reduce their mission effectiveness and thereby degrade the ability to defend the nation.

As discussed in a prior section of this report, the only currently proven mitigation techniques to prevent compromising U.S. air defenses is to ensure wind farms are not within radar line of sight of fixed-site air defense radars. As illustrated by Figures 4 and 31, radar line of sight near the surface of the earth is dependent upon the height of the radar unit, the height of the wind turbine, and the separation distance between them. Additionally, terrain irregularities, of the type illustrated in Figure 32, between the radar and the wind farm can significantly reduce the distance to where the wind turbines will no longer be within radar line of sight. Alternatively, a substantial elevation difference between the radar and the wind farm can produce a similar effect. Since all these parameters are site specific, each proposed wind farm would need to be evaluated on a case-by-case basis for the present.

The DOD/DHS Long Range Radar Joint Program Office already has established an informal consultation service to work with wind farm developers to assist them in identifying locations where radar line of sight concerns could exist. This approach should be continued and possibly expanded to include other defense-related concerns. This informal advisory assistance should remain optional and not replace or supplant existing regulatory review processes.

A special note needs to be mentioned regarding protection provided during “special events.” As part of its support to the homeland security mission, the Department will, at times, deploy supplemental air defense assets to provide additional protection during special events such as the Super Bowl, the World Series, Olympic type sporting events, political conventions, and other major gatherings that could be targets for terrorists. Air defenders providing such supplemental coverage will require knowledge of the locations of all nearby wind farms so that they can optimally position and operate those supplemental assets. The assistance of the wind energy industry to compile and maintain a database that can provide such information in a readily accessible manner by air defenders would be highly desirable.

Missile Early Warning Radars

The EWR fixed-site radars are required to be able to detect and track exceptionally low-RCS objects at extreme ranges with high confidence and accuracy. This also includes a requirement to be able to accurately discriminate between closely spaced objects so that Inter-Continental Ballistic Missile delivered nuclear weapon reentry vehicles can be distinguished from potential countermeasures specifically employed to confuse defensive systems.

The early warning radars are large, high-power phased-array radar systems specifically designed to accomplish this task. The high power level is required to ensure adequate illumination of potential threat complexes at very long ranges. The phased-array antenna is designed to enable the main beam to be focused on such complexes. The critical technical performance requirement is to ensure that the signal-to-noise ratio (SNR) is sufficient to accomplish the detect, track, and discriminate functions.

A simplified analysis had been performed for the early warning radar at Cape Cod AFS to assess if a wind farm being proposed for construction in the Nantucket Sound area would impact that radar. This simplified analysis contained three specific faults. First, it incorrectly employed the sine function rather than the tangent function to calculate beam elevation as a function of distance. This particular error, however, was numerically insignificant since, for the small angle considered, the values for sine and tangent of that angle are almost equal.

The second error in that analysis was the failure to account for atmospheric refraction of the beam and curvature of the earth. At low altitudes, such as in the immediate vicinity of the radar antenna, the main beam will be refracted by the atmosphere. The result of this flaw is to incorrectly predict the elevation of the high sensitivity region of the main beam as a function of distance from the radar. This was a more significant error.

The third error was that the analysis assumed a wind turbine would only impact radar performance if it was located in the main beam. In point of fact, a wind turbine could provide “clutter” reflections to the radar if any portion of that turbine appears in any portion of the main beam or in the side lobes, were the resulting level of the reflected signal to exceed allowable noise thresholds. If that were to occur, it would reduce the SNR and thereby degrade the ability of the radar to detect, track, and discriminate the most challenging threat objects. This error, too, is a potential source of significant error.

Consequently, a more comprehensive analysis needs to be performed for these radars. Such an analysis should also include consideration of whether range gating or other possible approaches can be employed to mitigate impacts. This analysis should also seek to establish generalized “red zone” areas for U.S.-based fixed-site early warning radars so that locations for future wind farms can be selected without requiring additional studies. In this regard, such “red zones” should also consider impacts on “back lobes,” to the extent they may exist, so as to guide placement of turbines on either Cape Cod AFS or Beale AFB. The Department will be unable to assess if wind farms in the nearby vicinity of either fixed-site early warning radar will impact their performance until such a more comprehensive investigation is performed.

Air Traffic Control Radars

As with air defense radars, wind turbines within the radar line of sight of ATC radars can cause reduction in their capability to track aircraft by primary radar return. However, the primary radar element in an ATC radar employed for air traffic management is only one part of a system developed to ensure the safe and efficient use of U.S. airspace. Other elements of this system, for example, include SSR systems, flight rules, and published approach and departure procedures for military airfields and civilian airports.

The FAA has the responsibility for promoting and maintaining the safe and efficient use of U.S. airspace for all users, to include the military. The Department, consistent with the long tradition of cooperation with the FAA, is prepared to assist the FAA in any subsequent investigations or analyses the FAA believes may be required to assess how wind turbines in radar line of sight of ATC radars might influence the U.S. air traffic control management system. As such, the Department defers any recommendations in relation to this particular aspect to the FAA. As is standard practice, the Department will adjust its processes and operating procedures for U.S.-based ATC radars operated by the military consistent with any subsequent guidance developed by the FAA.

Weather Radars

A number of studies have been performed to explore the impact wind turbines can have on the performance of ground-based weather radars when located within their radar line of sight. The bibliography provides just a few references [15-18] for some studies that have been performed in both the United States and Europe on this topic.

The National Weather Service (NWS) of the National Oceanic and Atmospheric Administration has been exploring this aspect and sponsoring efforts to develop mitigation techniques. As such, the Department defers to the NWS regarding identification of impacts on weather radars and development of any necessary mitigation approaches. The Department is willing to provide technical assistance, when appropriate, where potential mitigation measures under development have specific applicability to air defense and missile warning radar systems.

Other Potential Impacts on DOD Readiness

The Department conducts its operations in an increasingly complex environment. Wind farm development has the potential to influence Department activities in such diverse areas as military training, testing and development of current and future weapon and other systems, security, and land use to name a few. As operational requirements vary from location to location, any particular characteristic of a wind farm may present a challenge in one location but not at others. In this regard, the challenges that may be posed often but not always, will be similar to those associated with construction of other large objects such as telecommunication towers and in this respect, are not, in fact, unique to wind farms. For example, the de-confliction of land or airspace is an issue that the Department manages in concert with other stakeholders on a daily basis.

The Department has developed and employed, for many years, strategies and mitigation techniques to effectively address those possible impacts. To date, the Department has not identified any specific information that would lead to the conclusion that those methods would not be similarly effective for addressing potential impacts from proposed wind farm developments as they relate specifically to the subject of Other Potential Impacts on DOD Readiness.

Treaty Compliance Sites

The Department, in conjunction with the National Nuclear Security Agency (NNSA) of the Department of Energy, employs special sites to monitor compliance with the Comprehensive Test Ban Treaty. Those sites that employ seismic type sensors to accomplish this task are sensitive to background seismic noise. Increasing the ambient level of seismic noise will degrade the ability of these sites to perform their required task.

The UK has a similar site at Eskadalemuir and has conducted an in-depth study [19] to establish guidelines to ensure adequate offset distances for any wind turbines proposed for construction in that local area. The Department believes an effort should be undertaken to develop similar guidelines for U.S. sites employed to monitor treaty compliance. Additional information on this subject is provided in Appendix 2.

9. CONCLUSIONS

1. Wind farms located within radar line of sight of an air defense radar have the potential to degrade the ability of that radar to perform its intended function. The magnitude of the impact will depend upon the number and locations of the turbines. Should the impact prove sufficient to degrade the

ability of the radar to unambiguously detect and track objects of interest by primary radar alone this will negatively influence the ability of U.S. military forces to defend the nation.

2. The currently proven mitigations to completely prevent any degradation in primary radar performance of air defense radars are limited to methods that avoid locating wind turbines within their radar line of sight. These mitigations may be achieved by distance, terrain masking or by terrain relief and must be examined on a case-by-case basis.

3. The Department has initiated research and development efforts to develop additional mitigation approaches that in the future could enable wind turbines to be within radar line of sight of air defense radars without impacting their performance. Such development efforts should be continued. Such future mitigation techniques will require adequate test and validation before they can be employed.

4. A more comprehensive analysis is required to determine how close wind turbines can be built to early warning radars without causing negative impacts on their performance.

5. The FAA has the responsibility to promote and maintain the safe and efficient use of U.S. airspace for all users. The Department defers to the FAA regarding possible impacts wind farms may have on the Air Traffic Control (ATC) radars employed for management of the U.S. air traffic control system. The Department is prepared to assist the FAA in efforts the FAA may decide to undertake in this regard.

6. The Department is prepared to assist the NWS, where appropriate, in its efforts to develop mitigation techniques for ground-based weather radars where such techniques may have mutual benefit for Department systems.

7. Wind turbines in close proximity to military training ranges, as well as test and development sites, can adversely impact the “train and equip” mission of the Department. Existing processes to include engagement with local and regional planning boards and development approval authorities can be employed to mitigate potential concerns in relation to this.

8. Construction of wind turbines near Comprehensive Test Ban Treaty monitoring sites can adversely impact their performance by increasing ambient seismic noise levels. Analyses should be performed to develop appropriate guidelines regarding how close wind turbines may be built to such sites.

9. Given the expected increase in the U.S. wind energy development, the existing siting processes as well as mitigation approaches need to be reviewed and enhanced in order to provide for continued development of this important renewable energy resource while maintaining vital defense readiness.

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APPENDIX 1. POLICIES EMPLOYED BY SELECT NATO COUNTRIES

Several European governments have developed policies and procedures to address the siting of wind turbines in locations to reduce their impact on air defense and air traffic control radars. The policies vary considerably, reflecting different degrees of understanding that government policymakers have of the effects that wind turbines have on radar, different radar systems employed by that country, and different relationships between the military and industrial communities of that country. This appendix briefly describes the current policy employed by each of several NATO governments in regulating/influencing the placement of wind turbines in the vicinity of radar systems.

In November 2005, the Department, in cooperation with the UK Ministry of Defence, co-sponsored a NATO research and development study on this topic. The specific goal of that study is:

> To assess studies, analyses and field trials already conducted by the participating member nations to enable identification of gaps in understanding of underlying phenomenology. To develop a coordinated approach to address these gaps and any other concerns raised by participants. Finally, to develop a coordinated plan to conduct the necessary studies, analyses, or field trials to obtain any additional data deemed to be essential to fully comprehend this issue.

United Kingdom

As a result of several years of extensive flight trials and analysis described elsewhere in this report, the United Kingdom has the most robust understanding of the various effects that wind turbines have on their specific air traffic control (ATC) and air defense radar systems. Their regulatory process has undergone considerable evolution to reach its current state.

For UK ATC radars, the civilian operators must always honor the presence of displayed radar returns. Thus, displayed returns from wind turbines must be treated as real aircraft. Under instrumented meteorological conditions, ATC must be used to ensure safe separation between aircraft, including returns from wind turbines. On this basis the UK policy is that a wind farm close to an airfield is not compatible with ATC operations. A minimum lateral separation of 5 nmi should be maintained where critical ATC operations take place.

For UK air defense radars, the radar operators must be able to reliably track all aircraft that could pose a threat. The operators must include the ability to track by primary radar alone if necessary. UK studies to date have concluded that the radar’s probability of detection is reduced in air space over wind turbines due to technical aspects of radars and the large radar cross section of wind turbines, and no mitigation solutions have yet proven to provide the required level of radar coverage. On this basis, the UK Ministry of Defence must be consulted on all proposed wind turbines that are within the radar line of sight of an air defense radar, regardless of distance.

Germany

The major concern of the German government was the shadowing of targets by wind turbines when it developed its wind farm policy. A "protection zone" of 10 km around all military ATC radars is protected by German law. An "area of interest" is defined as the region up to 18 km from the ATC radars. The German policy is that specific permission for construction of obstacles (buildings, high-voltage lines, wind farms, etc.) must be granted by the German Defense Administration. For wind turbine proposals the Bundeswehr Air Traffic Services Office evaluates potential impacts to radar performance. Proposed construction within the "area of interest" is evaluated for line of sight, height, distance, turbine size, existing obstacles, radar frequency, and local topography. Technical comments and recommendations are requested from responsible military commands and a determination, including potential mitigation options, is communicated to the proposer by the German Defense Administration.

Netherlands

The Royal Netherlands Air Force (RNLAF) was concerned about the impact that shadowing by wind turbines had on radars. The policy of the Netherlands' government is that plans for wind turbines within 15 nmi of military radars must be submitted to the RNLAF, which then requests an impact analysis from The Netherlands Organisation for Applied Scientific Research (TNO). TNO then performs analyses based on modeling and simulation, helicopter-based field tests, and laboratory experiments and provides these to RNLAF, who makes the final determination.

Austria

The Austrian Air Force, based on limited field tests, is concerned about wind farms causing electromagnetic interference to radars, radio relays, and high-frequency direction finders as well as being obstacles to low-flying routes. Austrian policy is for wind turbine construction proposals to be evaluated by local authorities (mayor, district governor) in consultation with the Austrian Ministry of Defense. For turbine proposals further than 10 km from an air-defense radar no objections are raised; between 5 and 10 km an objection is raised unless the mast and gondola are outside the coverage volume (i.e., the radar line of sight of the area that the radar surveils) and the angle of obstruction is less than 5%; inside 5 km an objection is raised unless the whole turbine is outside the coverage volume.

Norway

Norway is concerned about false tracks from wind farms within 50 km of a military radar. Approval for construction is obtained from the Ministry of Oil and Energy after consultation with the Ministry of Defense and its research establishment and defense components. Possible mitigations that are considered include adjustments to the wind farms, adjustments to the radar (if the cost is less than $3M), or moving the radar/purchasing a new radar (if the costs to adjust the radar are greater than $3M).

APPENDIX 2. IMPACTS ON TREATY COMPLIANCE SYSTEMS

In addition to impacts on defense radar systems, wind turbines generate seismic and infrasound noise that could potentially contaminate monitoring stations providing data to support the Comprehensive Test Ban Treaty (CTBT) and U.S. nuclear explosion monitoring efforts.

United Kingdom Eskdalemuir Seismometer Array

The longest operating steerable seismometer array in the world is located at Eskdalemuir, in Scotland. The array is one of a global network that monitors compliance with the CTBT. This area has very little background seismological noise, and the seismometer array is very accurately calibrated, having monitored approximately 400 nuclear explosions at distances up to 15,000 km and numerous other seismic events (including detonations of conventional explosives, earthquakes etc.). It has recorded explosions from detonations as small as 100 tons of conventional explosives in Kazakhstan (about 5250 km away).

The Eskdalemuir area happens to be attractive to wind energy developers because of a high average wind speed, the availability of good connections to the national grid, and relatively few people living in the area who could object.

UK Microseismic and Infrasound Monitoring Studies

To assess the potential impact of wind turbines, in early 2004 the UK Ministry of Defence, the Department of Trade and Industry, and the British Wind Energy Association funded a study by Professor Peter Styles of the School of Earth Sciences and Geography at Keele University to collect and analyze data about wind farms and their seismic and infrasound noise generation. The study included review of existing research in the United Kingdom and United States, and empirical tests at Dun Law and Ardrossan wind farms. The Styles study reported their results and recommendations in July 2005. [19]

The Styles study included the installation and almost continuous 6-month operation of 10 three-component seismic sites at increasing distances away from the Dun Law wind farm, the deployment of 4 infrasound stations at certain distances from Dun Law, and the installation of accelerometers on wind turbine towers and strong motion detectors in the immediate vicinity of turbines at Dun Law and Ardrossan. The study analyzed the seismic background noise levels recorded at Eskdalemuir at different times and with different weather conditions. Seismic background noise results from several different sources including: cultural, which includes vehicle and railroad traffic; coastal noise, which results from ocean waves and surf, and local weather and seasons, which are storm and wind-produced. Styles concluded that seismic and infrasound noise was produced by wind turbines, the seismic noise is at a primary frequency related to the frequency at which the turbine blades pass in front of the support post of the turbine, this frequency covers a broad range from about 0.5 Hz to about 10 Hz, and this noise can be detected at distances greater than 10 km from the turbines. Styles found that at Eskdalemuir, wind was the predominant factor in noise and determined the median rootmean-square vertical displacement of a seismometer on windy days is 0.336 nanometers thereby establishing the level of anticipated background noise.

UK Government Policy Concerning Wind Farm Development near Eskdalemuir

The Styles study also developed a method to estimate the seismic noise created by wind farms. The study made recommendations concerning the amount of additional noise that the Eskdalemuir array could tolerate, what impact that would have on its operational performance, and how best to constrain wind farm development near it to maximize wind energy output while remaining under this tolerable additional noise amount.

The study assumed that the maximum additional noise "budget" that could be accepted from wind farm development near the array to be 0.336 nanometers. This means a potential doubling of the background noise level and with the model of noise and detectability they present, the threshold of detection would rise from 100 tons in Kazakhstan (distance 5250 km) to about 160 tons.

As a result of this research the UK Ministry of Defence has prohibited the construction of wind turbines within 10 km of Eskdalemuir. Turbine development between 10 and 50 km is constrained to not exceed the cumulative noise "budget" outlined above. There are no restrictions on wind farm development outside of 50 km.

United States Monitoring Activities

In contrast to the single International Monitoring System (IMS) auxiliary monitoring station in the United Kingdom, there are 4 primary IMS seismic stations and 10 auxiliary IMS seismic stations located in the United States. In addition to the IMS stations, there are several stations of the U.S. Atomic Energy Detection System (USAEDS) located in the United States. The USAEDS stations provide data for the U.S. nuclear explosion monitoring effort.

Recommended U.S. Approach

The methodology used by Styles in measuring the noise spectrum of wind turbines and assessing their effect on array sensitivity is comprehensive and based on sound scientific principles.

The United States should adopt a similar methodology to assess the impact of wind farms on U.S. monitoring activities and to develop objective criteria for evaluating wind farm development activities near their location. Since seismic background noise varies from site to site, site-unique measurements are needed for U.S. sites. A decision about what level of additional noise is acceptable also needs to be made. In addition, the measurements of seismic noise generated by wind turbines that Styles made must be updated to reflect the increased size of SOA wind turbines. This recommended approach should undergo a peer review within the seismic monitoring community to ensure all concerns and possible alternative courses of action are robustly examined.

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Comparing Statewide Economic Impacts of New Generation from Wind, Coal, and Natural Gas in Arizona, Colorado, and Michigan

S. Tegen

Technical Report
NREL/TP-500-37720
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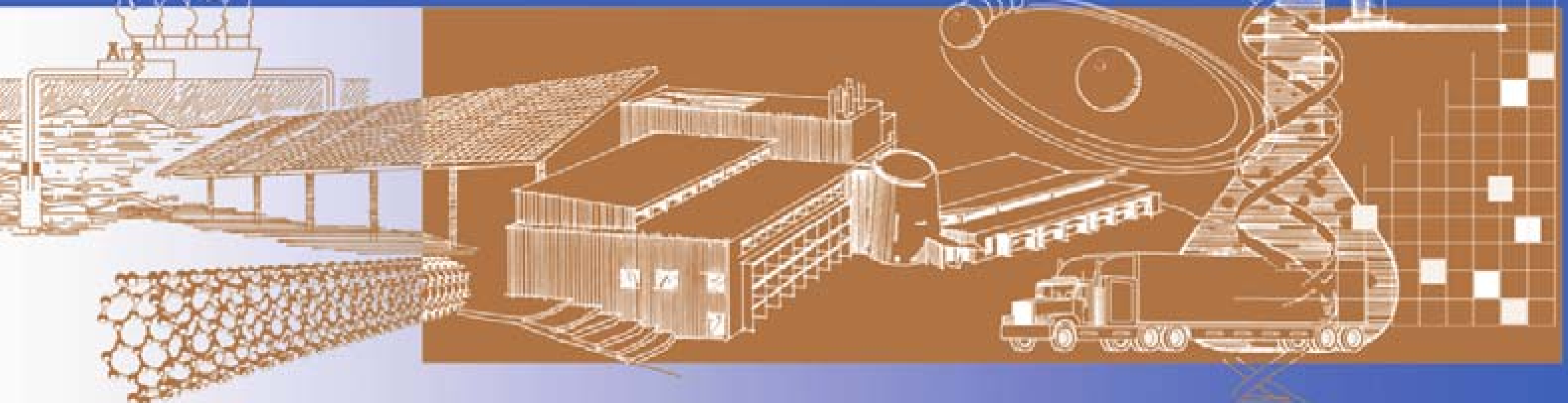

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Abstract
With increasing concerns about energy independence, job outsourcing, and risks of global climate change, it is important for policy makers to understand all impacts from their decisions about energy resources. This paper assesses one aspect of the impacts: direct economic effects. The paper compares impacts to states from equivalent new electrical generation from wind, natural gas, and coal. Economic impacts include materials and labor for construction, operations, maintenance, fuel extraction, and fuel transport, as well as project financing, property tax, and landowner revenues. We examine spending on plant construction during construction years, in addition to all other operational expenditures over a 20-year span. Initial results indicate that adding new wind power can be more economically effective than adding new gas or coal power and that a higher percentage of dollars spent on coal and gas will leave the state. For this report, we interviewed industry representatives and energy experts, in addition to consulting government documents, models, and existing literature. The methodology for this research can be adapted to other contexts for determining economic effects of new power generation in other states and regions.

Summary
This paper compares direct spending in Arizona, Colorado, and Michigan on the new construction and operation of three types of power plants: wind power, a natural gas combined-cycle baseload plant, and a coal-fired power plant. We follow the flow of money for each new plant and measure which dollars would be spent in Colorado (for example, dollars paid to a Colorado company to purchase concrete for a plant foundation or dollars spent on Colorado concrete workers' salaries). To reach a fair comparison, spending is calculated based on the same amount of energy generated by each plant—approximately 2,000,000 megawatt-hours (MWh) per year.[1] This amount of electricity would be generated by a 270-megawatt (MW) natural gas plant with an 87% capacity factor. Rated capacities of the coal and wind plants were adjusted so that they would generate the energy equivalent to the gas plant. The coal plant would be 280 MW in Arizona and Colorado but 300 MW in Michigan (VanderVeen 2005).[2] The wind plant capacity will vary in each state according to the wind regime. The components of each power plant included in this analysis are parts and labor for construction, operations and maintenance (O&M), fuel extraction, and fuel transport, in addition to money spent on financing, landowner royalties, and property taxes.

Research components:
- Construction
- Operations and maintenance
- Fuel extraction
- Fuel transport
- Land leases
- Financing
- Property taxes

[1] In this study, coal, gas, and wind comparisons are based on an equivalent amount of energy produced. Each resource will produce the equivalent energy from a 270-MW natural gas plant with a capacity factor of 87%. To equal the output of the gas plant, this means that a coal plant with an 80%-85% capacity factor will need 280 MW of generating capacity, and wind farms with a capacity factor of 25%-35% will need 680 MW-900 MW. Capacity factors for wind were determined by aggregate data from developers in each state.
[2] According to the assumption in the VanderVeen report for the Michigan Public Service Commission that a coal plant will have the capacity factor of 80% versus 85% in Colorado and Arizona.

Of the various impacts to the state economy involved in power generation over 20 years, each state has varied results that show equivalent generation of wind power will bring the highest direct economic benefit to the state. Tax revenue (especially for wind plants) plays a significant role in the benefits to the state's economies because a larger tax base makes it possible to provide more funding for public goods, such as parks, roads, and schools. If power plant owners negotiate a deal with localities in which they build so that they are exempt from property and sales taxes, the local economy may benefit from some job creation or fuel sales, but it will not receive what can be very significant property tax benefits over the life of the plant. As shown in the results, much of the labor force for plant construction, as well as for operations, is often brought in from outside each state. When the labor forces for construction or fuel transport come from within the state's borders, economic impacts can be considerable, regardless of where the fuel is initially extracted. Of course, if coal or gas comes from the same state where the power plant is located, the economy is more likely to benefit from the sale of the fuel.

Results are based on the best available data from industry and government sources. Examples of uncertainties in the data are represented for each generation technology in the Results section of this paper. The methodology detailed in this report is useful for researchers in regions where there are questions about which energy source to build next and which generation source most benefits the local economy. Results may also help inform decision-makers who want to maximize benefits to their state by providing an energy-equivalent method of comparison.

Introduction and Background

In the United States, the need for additional electricity generation continues to increase due to the growing population and demand from energy consumers. The Department of Energy predicts that this growth will continue (Figure 1).

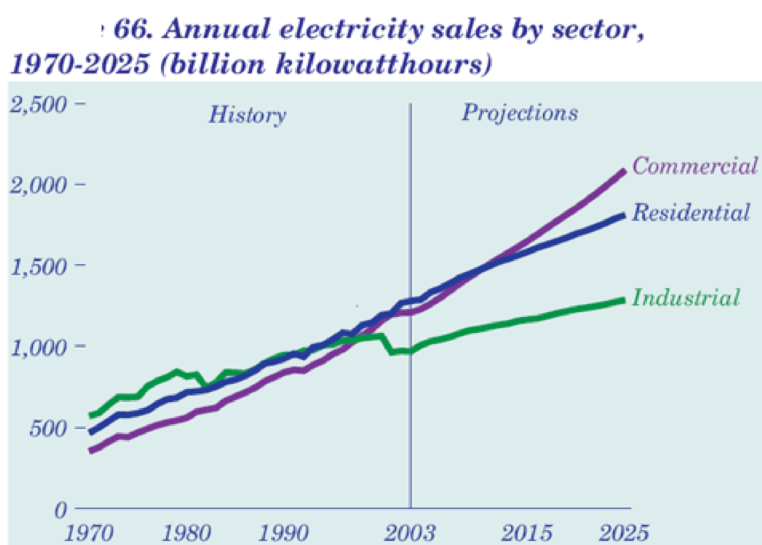

Figure 1. Prediction of annual electricity sales from 1970 – 2025 by the Department of Energy's Energy Information Administration (released February 2005)

With a growing focus on domestic power resources for energy independence and the need for new employment opportunities, it is important for decision-makers to understand the economic impacts of energy generation sources on their local economy. For example, when a new power plant is built, laborers will be needed to pour the concrete for the foundation of the plant. If the workers come from within the state, this new project will contribute to the state's economic well-being by paying state residents.

This paper compares the flow of money into and out of states from three potential sources of new electricity production. We examine the impact of developing three new hypothetical power plants to produce electricity from coal, natural gas, and wind. We also explore how much money each new plant would contribute to Colorado's economy by adding labor from Colorado, equipment sold in Colorado, landowner payments, and property taxes. As indicated in Table 1, coal, gas, and wind comparisons will be based on the amount of energy produced.[3]

Table 1. Energy Equivalents

	Capacity Factor	Equivalent MW Needed	MWh Produced per Year
Coal	80%-85%	280 - 300	~ 2,084,880
Gas	87%[4]	270	~ 2,057,724
Wind	25%-35%	680 - 900 (1.5-MW turbines)	~ 2,084,880

The equivalent megawatts are determined by multiplying the capacity by the capacity factor by the number of hours in a year. For example:

$$\textbf{270MW x 0.87 x 8760 hrs/year = 2,057,724 MWh}.$$

The results of this study may be used in policy analysis for issues such as potential renewable portfolio standards and system benefits charges or in decisions based on maximization of economic benefits to states from their natural resource potential. Results also indicate how much the specific components of new energy generation will benefit the states' economies.

Existing Research

Many informative studies about the impacts of electricity production have been performed, including an examination of which energy sources create the most jobs or produce the greatest advantages for consumers or the environment (Madsen et al. 2002; National Wind Coordinating Committee 1997; Clemmer 2001; Goldberg et al. 2004; Kaas Pollock and Gagliano, 2004; Regional Economics Applications Laboratory 2001; Wind Energy Creates 1995). The body of literature about wind's economic development impacts and the uncertainty of gas pricing is growing (Wiser and Kahn 1996), as well as

[3] Energy from each source is an estimate of potential generation for comparison purposes and is independent of operational constraints, including those that might be driven by changes in fuel prices.
[4] 87% is the highest capacity factor given to a natural gas power plant by the Energy Information Administration. This is used as a basis for comparison. Currently, natural gas prices are too high to make construction of a baseload natural gas plant economically feasible, but prices of gas and other resources will vary in the future. This study does not consider costs to consumers, but it should be noted that at present fuel prices, an 87% capacity factor is unlikely.

several modeling tools to calculate economic impacts (Goldberg et al., 2004; Costanti 2004). The methodology for this report was initially developed for a paper describing the economic benefits to Colorado published in the Global WINDPOWER 2004 conference proceedings (Tegen 2004). But a comparison of multiple states' resources and their direct economic impacts from sources of new utility-scale generation has not been conducted. Unlike other work, this study compares direct impacts specific to statewide economies. Wherever possible, data were gathered from state-specific energy companies[5] and energy experts, instead of using national averages and extrapolating costs for each component.

Goal and Scope

The scope of this project is the measure of direct economic impacts from new sources of electricity. In other words, we calculated how much money will be spent in each state for salaries, purchasing materials, land revenues, financing, and taxes when new power plants are built and operated. For each resource, the study compares the following components of new electricity generation:

- Materials and labor for construction
- Materials and labor for O&M
- Materials and labor for fuel extraction (gas well or coal mining)
- Materials and labor for fuel transport (including railroads, shipping, and gas pipelines)
- Project financing
- Landowner revenues
- Property taxes

When analyzing direct economic impacts of coal, we include parts and labor for coal mining and coal transport (from the mine to the power plant by railroad or ship) under the fuel component for each state analyzed. For natural gas, we include parts and labor for gas extraction at the wellhead and parts and labor for gas pipeline costs. This research does not include indirect or induced effects of energy production (e.g., plant construction worker's hotel bills).[6] The new power generation facilities are assumed to be grid connected. Other assumptions are found in the Assumptions section.

The primary goal of this research is to provide a careful state-specific comparison of the money flow from new power generation. Project results are not meant to represent national averages or economic impacts in other locations. However, strategies and models for data gathering used in this study will be helpful for others working on similar projects (see Lessons Learned). It is important to remember that data for this paper were gathered in early 2005 and that the results presented here reflect these inputs. The

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[5] Companies include developers, utilities, municipalities, private wind generators, pipeline companies, coal railroad companies, and energy-equipment companies.

[6] Indirect effects are additional economic activities stimulated by direct spending associated with power plant construction and operations (e.g., hotel revenue from out-of-state workers). Induced impacts are increases in economic activity associated with increased disposable income created by power plant constructions, operations, and other power plant spending (e.g., increased spending on clothing due to increase in family incomes from power plant work salaries).

purpose of this paper is to introduce a useful methodology. When utilizing this methodology in the future, inputs should be changed to reflect the most current data available.

Methodology

The methodology for this project includes a number of data-gathering techniques. In addition to the aforementioned interviews with analysts, government energy offices, and industry contacts, we also conducted literature searches. We used the BaseCase database from Platts, a division of the McGraw-Hill Companies, Inc., and the jobs and economic development impacts (JEDI) economic development analysis tool for wind projects from the National Renewable Energy Laboratory (NREL).[7] After sufficient economic data were gathered for the chosen energy sources, we sent the assumptions to energy experts for each resource and compiled in a spreadsheet format most useful for comparisons of each power source.

For each component of the study (e.g., labor for natural gas extraction), we compared the best-estimate value based on $/kilowatt-hour (kWh).[8] Next, sensitivity analyses were performed to determine how much higher and how much lower the dollar value could potentially be. For example, if some industry reports conclude that average annual O&M costs for natural gas are $15.50/kilowatt (kW, nameplate capacity), but reliable models report that the same costs are $27/kW, it is necessary to conduct further analysis and determine high and low ranges around a best-estimate dollar amount. Each component of this study is represented by a best-estimate cost with a range of uncertainty above and below it, when applicable. It is necessary to explain each dollar category or "component" so that the scope, assumptions, and uncertainties are clear when viewing the project results.

Components of the Estimated Direct Economic Impacts

Construction

For each energy resource, we conducted many interviews to determine prices of new construction. We assumed that construction would begin in 2005. Interviews were primarily with industry contacts or from each state's energy experts. In Michigan, we relied on experts and the Michigan Public Service Commission's current reports. The construction component includes the capital cost of equipment as well as overhead, legal and permitting costs, and engineering. It also includes the cost of land, except for annual land-lease payments (e.g., to farmers paid for wind turbines on their land). The construction phase of a new power plant will vary for each generation technology. Constructing a coal plant of this size can take 3 to 6 years, whereas natural gas plants typically take 1.5 to 2 years, and wind plants can take between 6 months and 1 year to develop. Wind generation of such large size would likely take about 1 year.

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[7] An easy-to-use tool to analyze potential jobs, economic development, and impacts from wind development. www.windpoweringamerica.gov/filter_detail.asp?itemid=707

[8] Some costs are typically reported in $/kW or $/megawatt, but we used a $/kWh calculation for a fair comparison.

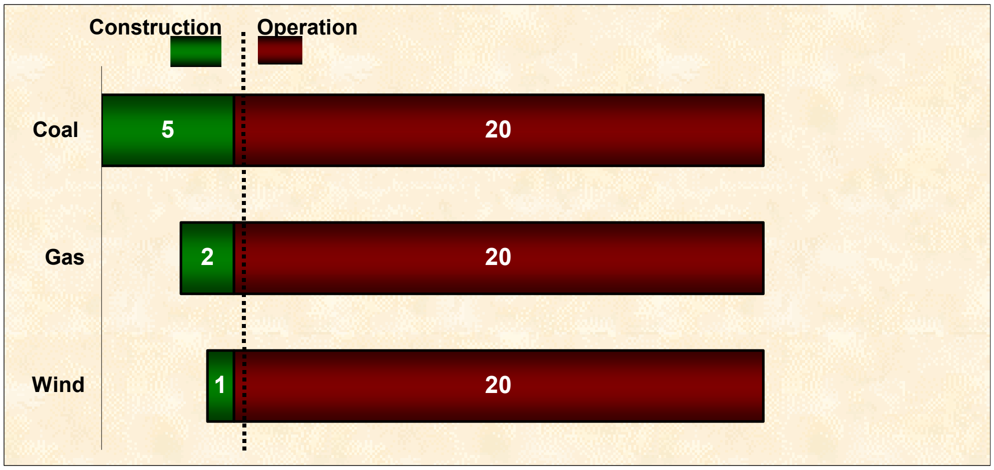

Figure 2. Construction lead time for coal, gas, and wind plants

Financing
It is unlikely that an in-state bank would finance a utility-scale power plant project. Local banks are increasingly willing to finance new wind projects, but those projects are usually much smaller than 280-MW projects (typically 50 MW or less). A variety of financing techniques exist for power plants, but this study assumes financing by a utility or large bank. Options for funding a wind project are expanding, and there are examples of community-financed projects in which community members own the project or team with larger corporations to fund a wind project. In the latter case, known as the "flip" model, a corporation owns the wind project for the first 10 years while realizing tax incentives and then "flips" ownership to the local community. There are many options for funding wind generation. For this study, whether the project is financed in state and by what amount are important elements. We assumed that none of the financing for new power generation would be from within the states, based on interviews with Colorado lenders. Researchers may choose to use this methodology with the flip model or other community financing options and learn how in-state benefits are increased.

Operations and Maintenance
O&M spending from a new power plant includes unscheduled but routine maintenance, preventive maintenance, and costs of scheduled major overhauls. Some O&M estimates also include property tax and landowner payments, but this study separately examines those and does not incorporate them under this heading. O&M spending was difficult to determine for natural gas, whereas the energy community agreed on coal and wind O&M spending. Dollars spent for natural gas O&M ranged from $7.6/kW to $20/kW. We used $10-$14, depending on state data, for our average because it is from actual recent power plant figures (BaseCase). We used actual data from new power plants whenever possible and spoke with representatives from each energy generation source to determine the breakdown between parts and labor. In most cases, industry employees agreed that labor (not materials) is the much larger component of O&M costs (between 70% and 99%). One developer said labor might only comprise 60%, but most agreed it was a higher percentage. Variations are reflected in sensitivity analyses.

Fuel Extraction and Transport

This study includes the extraction of gas and coal from the well or mine and the transport by pipeline or railroad to the utility's power plant. We spoke with representatives from the railroads and pipeline industries to obtain breakdowns of fuel costs (extraction vs. transport and labor vs. parts). Breakdowns for coal vary greatly. For example, if the coal is from Colorado, most of the direct dollar outflow for transport will also be by Colorado laborers, and this makes a significant difference in the results. In Michigan, none of the coal is from Michigan coal mines, but a large coal transport industry (rail and ship) is based in Michigan; thus some of the direct expenditures for transporting the imported coal will benefit Michigan's economy.

Using this scope of work, wind power has no economic benefits in the category of fuel extraction because the wind is free. Of course, having zero fuel costs could be viewed as a cost advantage for utilities and their customers, but this study considers the state economy's overall impact from new power generation, not utility or customer costs or prices.

Landowner Revenue

In this study, landowner revenues for power generation apply only to wind power development. Studies show that the most common way for utilities to add wind to their resource portfolios is to purchase generation from private companies instead of owning and operating wind farms (Wiser and Kahn 1996, p.1). This means that the electric output from a privately owned wind farm, such as the wind farm in Lamar, Colorado, is sold to investor-owned utilities (IOUs) under long-term contracts. The company that owns the wind farm usually leases land for its turbines from rural landowners, who are typically farmers or ranchers. Wind developments are sited in rural areas for various reasons, including wind speeds and site selection processes. Annual payments range from $1,500 to $6,000 per wind turbine per year, depending on individual contracts and size of turbines.[9] Land leases can be structured in several ways. The most common in the wind industry is to base lease payments on a percentage of gross revenue from wind power production. Normally, a guaranteed minimum annual payment is included in a lease to cover periods in which the project may be inoperable (National Wind Coordinating Committee). Some landowners choose to accept payments per turbine instead of payments based on gross revenue so that they are assured a set income.

It is possible for a utility to own the entire wind project and make payments to farmers directly or even to buy the land outright. In another situation, an outside company, either a utility or non-utility, could purchase land for wind turbines up front and therefore not be required to make land payments to landowners after the initial payment. These cases are unlikely but possible.

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[9] Net landowner revenues: landowners must calculate their cost of lost productivity and subtract it from their income per turbine. Ranchers are usually not affected because animals can graze among installed turbines. A Pacific Northwest study shows that farmers gain approximately 85% of their gross revenue when land loss is figured in.

For coal and gas plants, power plant owners usually purchase their land and include this under their construction costs. Much less land is needed for a coal or gas plant than for a wind farm, considering different technologies and the 25% to 35% assumed capacity factor for wind compared to much higher capacity factors for fossil-fuel generation.[10] The larger amount of land required for wind projects benefits rural landowners in the form of landowner payments. Although wind plants need access to large land areas, they only use a small fraction for roads, turbine foundations, and electric equipment. More than 90% of the land used for a wind farm can still be used for crops or grazing.

Property Taxes

As mentioned, wind power requires much more land than either a natural gas or a coal plant. More than 400 1.5-MW turbines are required to produce the energy equivalent to a 270-MW natural gas plant with a capacity factor of 87%. Utilities and plant owners may be exempt from property taxes depending on contract negotiations or state incentives. However, if taxes were collected, tax revenue would be greater from a wind plant than from a fossil fuel plant due to the increased size of the project.[11]

In Colorado, property taxes are paid to counties, and all county property taxes are assessed by the State Office of Taxation (the State). The State bases assessments on the value of the utility's or plant owner's "business valuation," or the sum of real property, personal property, tangible assets, and intangible assets.[12] The State then takes 29% of the business valuation to be the assessed value of the company. The assessed value is communicated to each company and county, and property taxes owed to the county are based on power plant location. For example, if Xcel Energy Corporation were to build a coal plant in Pueblo County, Colorado, they would negotiate tax rates with Pueblo County assessors. Counties determine the amount of property taxes based on mill levies, which are specific to each county but are usually higher in rural areas.[13] Annual county mill levies range from 3% (La Plata County) to 9.9% (Phillips County).[14] For this research, we assume 7% in Colorado. Because of the popularity of granting coal and gas plants exemptions from property tax in Colorado, this study assumes that the coal and gas plants will pay property taxes all 20 years, but during the first 10 years, they will only be subject to half of the property tax.

Tax exemption is often automatic for municipally owned utility plants. Tax exemption can play an important role in new power plant development for investor-owned or

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[10] Much less land is needed for the actual power generation. However, land impacts are greater when the entire life cycle of the resource is considered. For example, coal mining sites, including roads and disposal sites, were not included in the scope of this research.

[11] In some states, wind energy projects are exempt from property taxes resulting from increased property value because of wind plant development (NWCC Wind Energy Series).

[12] It is common for utilities to operate in more than one state. In such cases, the Colorado Office of Taxation assesses companies based on total historic cost (depreciation rate plus net book value of assets) per county. According to Deb Meyer, State Division of Property Taxation, intangible assets could be for items like franchising or the worth of a brand name.

[13] Mill levies are a specified rate: 1 mill equals 1/10 of a cent ($0.001) per $1 of property value used to determine the tax or assessment on property. Mill levy taxes are used for things like school districts and road improvements.

[14] Colorado tax information is based on conversations with Mark Walker of the State Office of Taxation.

privately owned utilities. Non-municipally-owned power plants may be exempt from property taxes unless they have non-operating properties, such as land that they do not use. Tax exemption is a great advantage to power plant owners. The utility will often negotiate a deal for tax exemption or partial tax exemption with counties in which they locate a power plant.

For example, in Colorado, agreements between Xcel Energy and the City and County of Pueblo state that, if Xcel builds a power plant there, the company would be forgiven 50% of the total in property taxes over the next 10 years. The City also agreed to forgive sales-and-use tax on the construction of the plant in return for a one-time $13 million payment, which may be used to construct a new building for Pueblo police (Amos 2004). Cities and counties negotiate deals like this because new plant construction and operations bring new jobs to the area. However, as results show, much of the construction and operations labor is brought in from out-of-state. For example, in-state coal plant construction labor accounts for less than 20% of total labor.

In Michigan, the assessed value, or "State Equalized Value," is equal to one-half of the total value for real and personal property. The state's average tax level applied to the assessed value is 5% for annual property taxes. Air and water pollution control equipment on power plants is exempt from property taxes.

Wind plants in Michigan will not be required to pay property taxes until the year 2013. According to the Michigan Economic Development Corporation, "Alternative-Energy Personal Property" … is exempt from the collection of personal property taxes. This exemption includes (1) "Alternative-Energy Systems," (2) "Alternative-Energy Vehicles," (3) the personal property of an "Alternative-Energy Technology Business," and (4) the personal property of a business not engaged in alternative-energy technology that is used solely for the purpose of researching, developing, or manufacturing "Alternative Energy Technology." However, it is common for a community to negotiate "host fees" in lieu of property taxes from $3,000 - $5,000 per turbine per year. After discussions with a Michigan wind developer about recent projects, we have assumed a $5,000/turbine/year payment for this study.

In Arizona, the assessed value of a plant is 25% of 80% of the installed project cost. Then mill levies are applied to this number to determine county property taxes. The average, and the assumed number for this report, is 7.6%.

Because of specifics of individual project negotiations, taxes for the average new power plant are difficult to predict accurately. As stated, it is fair to assume that a utility-owned plant will likely be partially tax exempt in Colorado, but a privately owned power plant will be required to pay county property tax (Wiser and Kahn 1996). In Michigan, we safely assume that wind projects will not pay property taxes until 2013. For this project, we took examples of current power plant tax estimates and average tax payments from existing plants and applied them to the appropriate size of the new plant. For wind, we used existing plant data in Colorado and estimates in Arizona, and we based Michigan assumptions from the Michigan Public Service Capacity Needs Forum.

Taxes paid on gas wells and for coal mines will not likely increase when 280 to 300 MW of generation are added to the state's system mix. New gas wells and coal mines are not required for this amount of electricity production, so taxes on these items were not included in this study. If all the coal or gas came from within the state and resulting extraction efforts were larger, or if the plant were of larger capacity, it is conceivable that the associated increases in well or mine taxes should be considered.

Sales Tax

We did not separate sales tax in this report. We assume that sales tax is included in the dollar amount of parts, such as the wind turbine shaft, or of processes, such as the natural gas plant construction. To calculate sales tax, a researcher would have to obtain information about which parts of the power plants, fuel extraction, and fuel transport come from within the state or come from a company with an office within the state so that the company may charge sales tax. For example, if wind turbine blades were manufactured in South America or Denmark, but the manufacturing company had an office in Arizona, the wind farm owner would be required to pay Arizona state sales taxes for the wind turbine blade. If the Danish company had an office in Wyoming instead of Arizona, no sales tax would be paid to Arizona. Most companies do not make any of this sales tax information available. However, future studies may include estimated sales tax based on state-specific models. For example, Colorado sales tax is 2.9%, and this could be added (or broken out from existing dollar amounts) to parts purchased in Colorado, depending on whether the sales tax is assumed to be included.

Discount Rate

For purposes of this research, results are displayed without a discount rate applied. However, discount rates of 5% and 7% were applied to some results, and direct spending can easily be calculated with a discount rate of the researcher's choice. In the Results section of this report, we show direct impacts without the discount rate, except when specifically noted. This is due to the wide range of discount rates used by government, policy makers, and industry.

State Specifics

The Components section of this report above has detailed each area of dollar flow, including some state specific information (see Property Taxes). The Assumptions section explains general suppositions for the paper. Some areas of inquiry require individual explanation for each state's energy background and attributes, which are in this section.

Arizona

In Arizona, most of the state's power comes from imported coal. (Coconino County, Arizona, has some coal mines, but they supply an electricity generation facility in Nevada). Coal for a new coal plant would likely come from Wyoming or New Mexico (Tri-State Generation and Transmission Association, Inc.). The new plant is assumed to be a sub-critical plant, based on the most recent Arizona coal plant proposals (Springerville). The coal plant's capacity factor is assumed to be 85%.

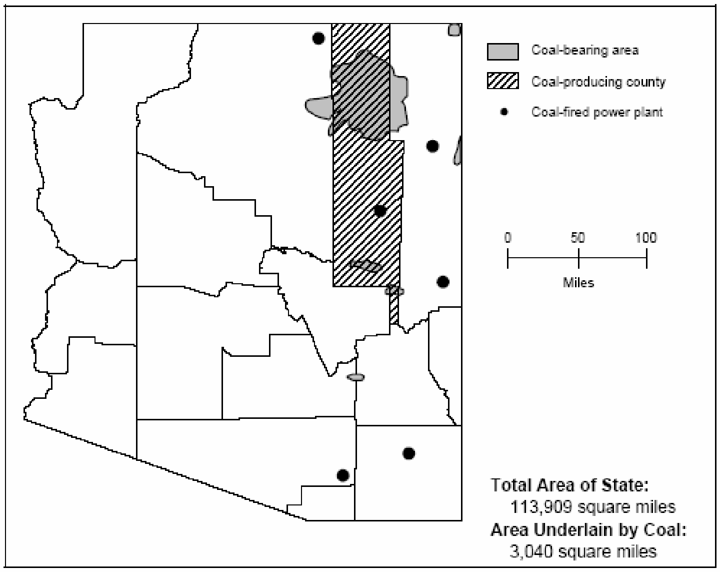


Figure 3. Arizona's coal-producing area. Source: EIA, 1999

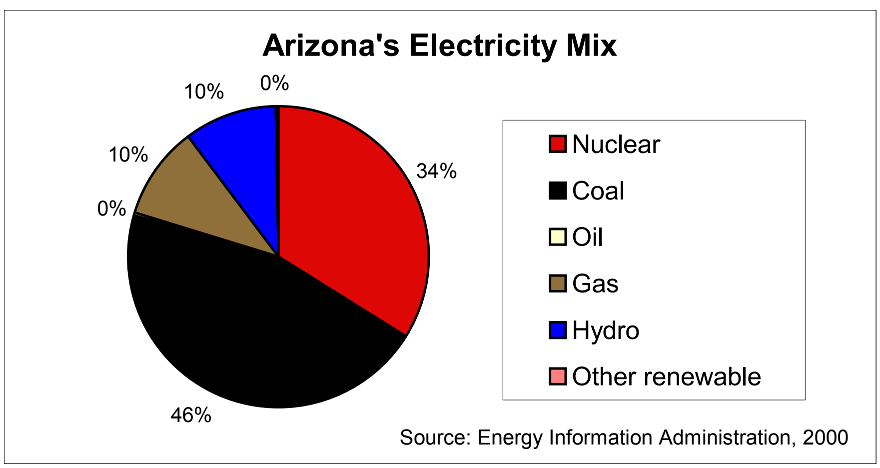


Figure 4. Arizona's electricity mix. Source: EIA, 2000

Arizona also imports its natural gas (see the Assumptions section for further aspects and complications on natural gas). The capacity factor for wind in Arizona is assumed to be 30% for this research, so the wind plant would require 520 1.5-MW turbines to equal 780 MW and generate the necessary amount of electricity.

Colorado

In Colorado, the coal plant is assumed to be a super-critical plant based on the most recent proposed coal plant in Colorado (Xcel Energy's Comanche III coal plant in Pueblo). Coal will most likely be transported by rail from the Powder River Basin in Wyoming. The coal plant's capacity factor is assumed to be 85%.

Colorado has natural gas fields, and this study assumes that 40% of the natural gas for the new plant comes from within the state's boarders. Colorado has a considerable wind resource, as shown by the pink and purple areas (Figure 5).

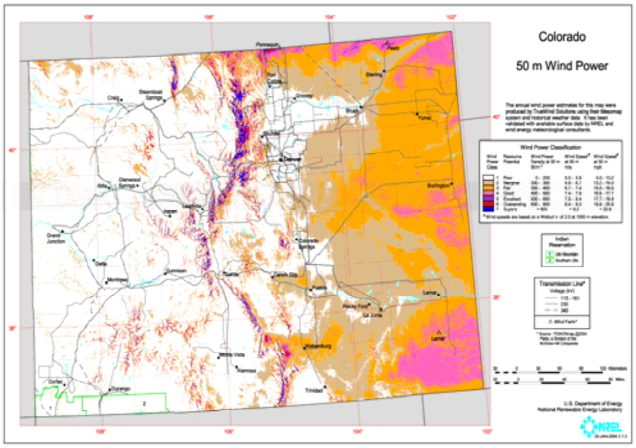


Figure 5. Colorado's wind resource at 50 meters. Source: NREL, 2004

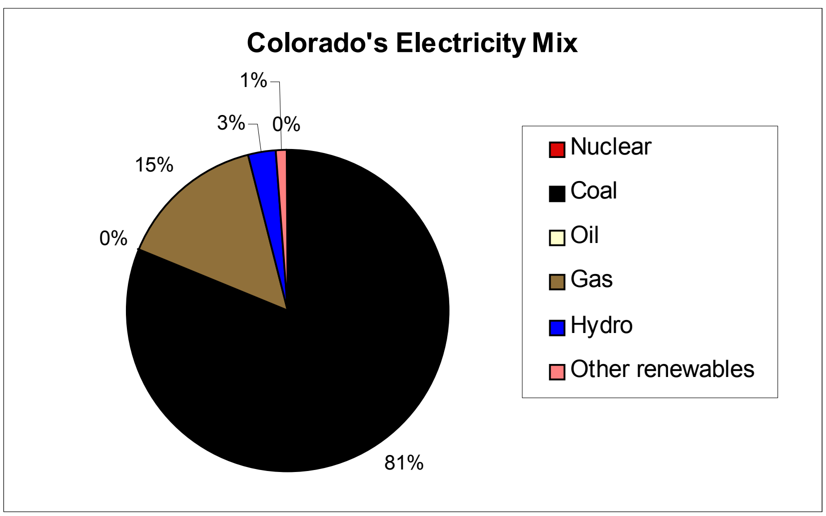


Figure 6. Colorado's electricity mix. Source: EIA, 2000

Michigan

Like Colorado, Michigan's power mix relies heavily on coal, with a small amount of natural gas and almost no wind power. Michigan also imports coal to feed its power plants. Michigan does have some natural gas extraction fields, so we assume that 25% of natural gas used in Michigan comes from Michigan. The multiple in-state pipeline, railroad, and shipping companies provide direct benefits to the economy. For example, if the coal is transported from Wyoming, some of the labor and materials for the railroad cars are from outside Michigan. For the base cases in this study, we assume that 50% of the natural gas transport labor is based in-state and 60% of the coal transport labor is based in Michigan. These current estimates are from a report for the Michigan Public Service Company (VanderVeen 2005).

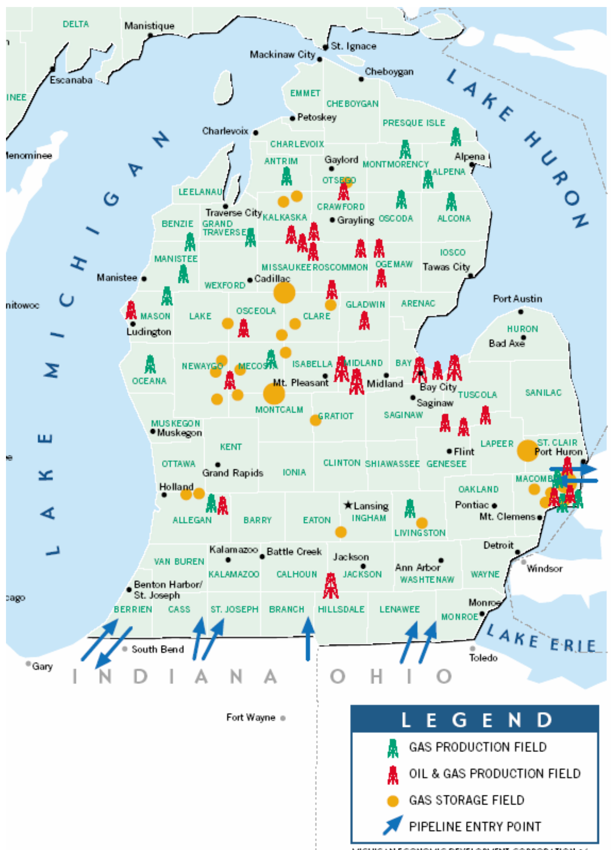


Figure 7. Michigan's gas and oil production fields. Source: Michigan Economic Development Corporation, 2000

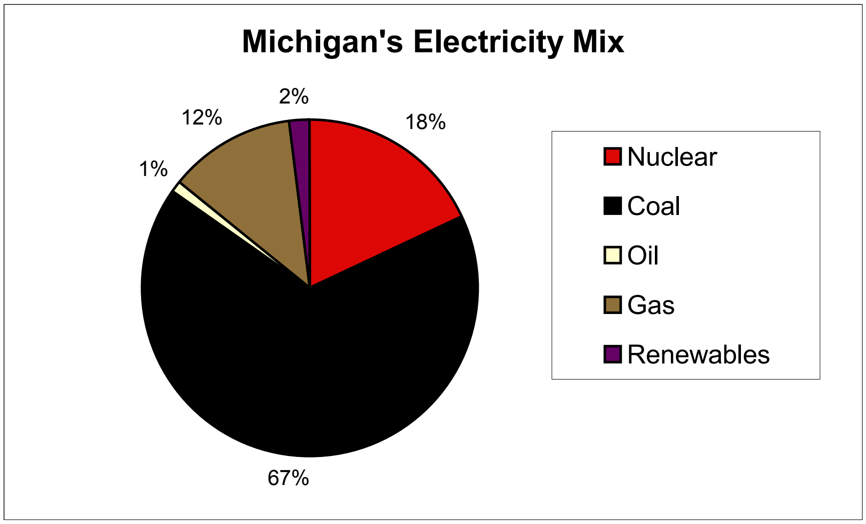


Figure 8. Michigan's electricity mix. Source: EIA, 2000

Assumptions

Assumptions for this study are based on scenarios that are most probable for building new energy-generation capacity. It is assumed that energy efficiency and demand-side management options have been considered earlier in the decision-making process. In this case, new energy generation is utility-scale and grid connected.

The new wind, coal, or gas power plant would produce approximately 2,000,000 MWh per year for 20 years, and construction would begin in 2005. Power would be generated in each state for its ratepayers. We used the most recently proposed coal, gas, and wind projects in each state to determine our assumptions.

The natural gas plant is assumed to be a baseload combined-cycle plant. It is very difficult to determine the exact wellhead in a power plant from which natural gas stems from (Figure 9). Natural gas flows through pipelines and is mixed with gas from many sources before it arrives at the plant. Interviews with 15 energy analysts and natural gas industry employees in and around Colorado provided answers that ranged from "most of our gas is from Wyoming" (Mercatur Energy) to "80% of the gas should be from Colorado if the plant is far enough from Colorado's borders" (Colorado Oil and Gas Commission). For this study, we assume that none of the gas used in the new power plant would be from Arizona, 40% of gas is extracted from Colorado's natural gas wells, and 25% of Michigan's gas will be from Michigan.

We also assume that the new gas plant would have a capacity factor of 87%. This is consistent with new efficient gas plants that are currently under construction.[15] However, at the present (May 2005) high fuel price, some companies choose to only run their gas peaking plants – not baseload (these plants are too expensive to utilize for electricity

[15] Energy Information Administration's maximum capacity credit assumption. Xcel Energy's combined-cycle gas plant in Fort Lupton, Colorado, was rated 86.5% in 2002.

because of the high gas prices). A report for the Michigan Public Service Commission assumes that natural gas has a capacity factor of merely 35% due to the heightened fuel prices (VanderVeen 2005). In this study, we assume that the price of natural gas will continue to fluctuate but will also be used as a baseload plant when costs for other generation (e.g., pulverized coal) and construction (steel, etc.) also increase in the future. One example of the market fluctuation is EIA data, which show that coal prices are also rising in each region of the country. These rising prices are for spot markets, not long-term fixed contracts, but they show the upward trend in prices nonetheless. The methodology for this report can be used with the assumption that resources have a much lower capacity factor, if required.

We assume that the gas project financing would come from the utility's regular financial lending institution (usually a large national or international bank not located within the state).

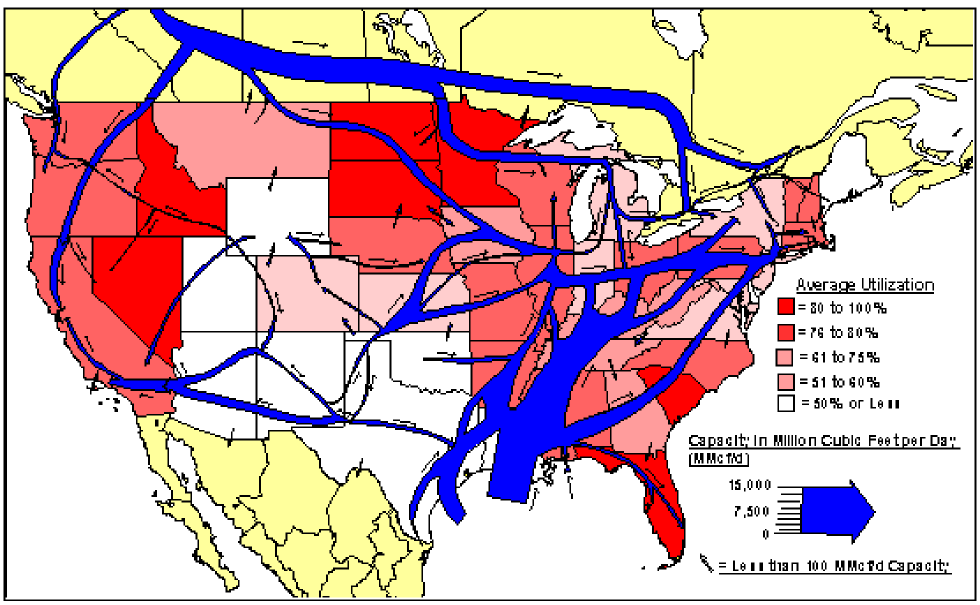
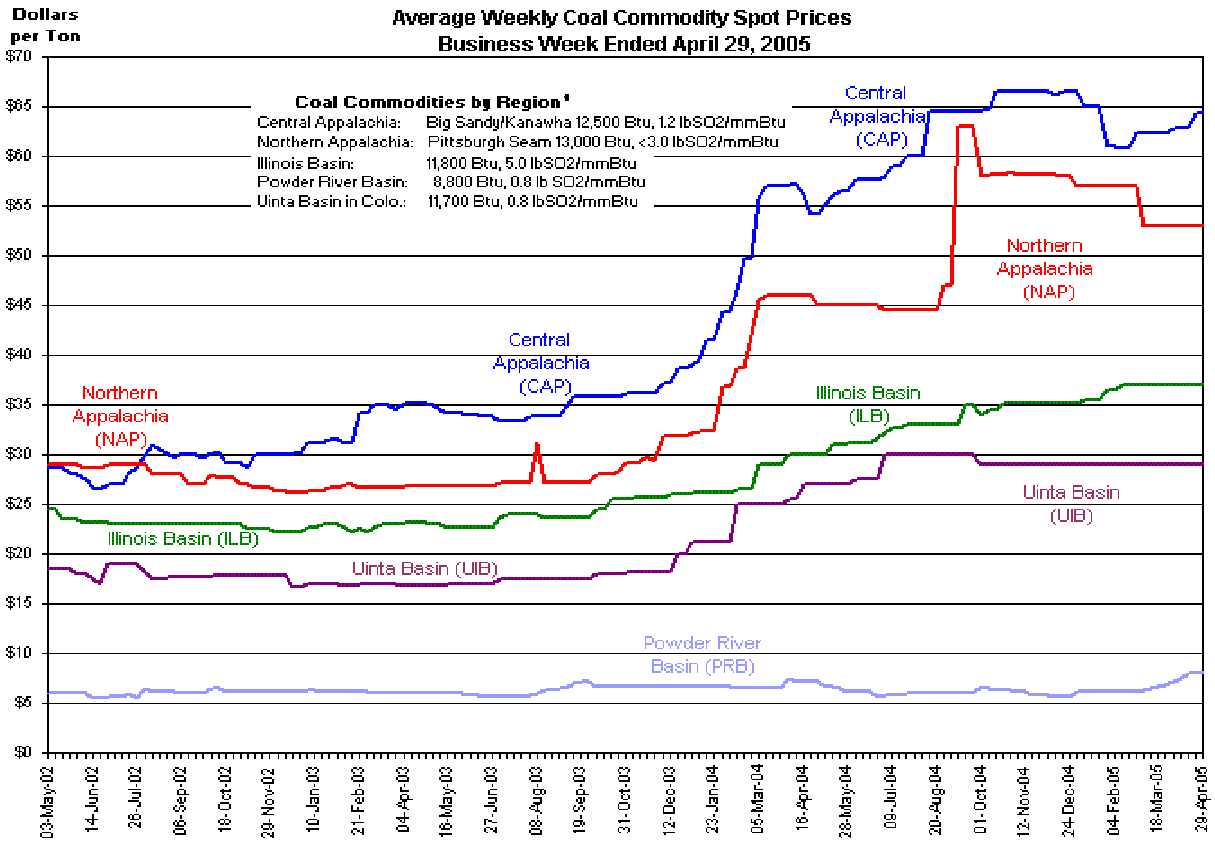


Figure 9. Natural gas transmission line capacities. Source: EIA, 2000

Making assumptions about natural gas prices today and for the next 20 years is risky and will inevitably be somewhat inaccurate. (See Figure 11 for obvious price shifts.) However, we use the EIA's assumptions and include high and low scenarios above and below those predictions. Since the Colorado report (2003 data) (Tegen 2004), prices for natural gas have continued to rise. The assumptions for natural gas base case prices in this study range from \$35/MWh to \$55/MWh, or \$5.2/MMBtu to \$7.9/MMBtu, to incorporate a range of prices. Assumed prices are based on data from actual natural gas plants in each state. Utilities running natural gas plants have long-term contracts for baseload natural gas, so they are not as vulnerable to spot market fluctuations.



[1] Coal prices shown are for a relatively high-Btu coal selected in each region, for delivery in the "prompt" quarter. The "prompt quarter" is the next calendar quarter, with quarters shifting forward after the 15th of the month preceding each quarter's end.
Source: with permission, selected from listed prices in Platts Coal Outlook, "Weekly Price Survey."

Figure 10. Average weekly coal spot prices ($/ ton) from May 2002 through April 2005. Source: EIA

We assume that the capacity factor for wind power will be 30% in Arizona, 35% for the wind farm installed in Colorado (Milligan, personal communication), and 25% in Michigan (VanderVeen 2005). We also assume that the landowner revenue paid to a landowner is a direct benefit to the state's economy. This study does not try to determine the next step for dollars brought into the economies by using a multiplier or other calculations.

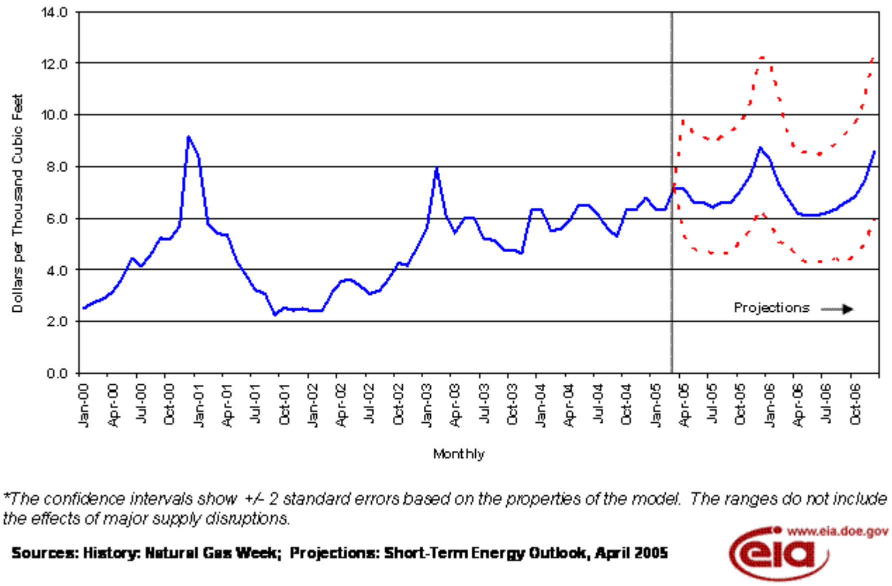


Figure 11. U.S. natural gas spot prices from 2000 to 2006 in $/ thousand cubic feet. Source: EIA

Results

The results show that benefits to the three state economies from energy resources vary greatly, depending on specifics of each power plant project and its contracts. For fossil-fuel-fired power, dollars spent on fuel are a significant benefit *if* the fuel is produced in state or transported by in-state industry and workers, or both. As expected, results show that states are positively impacted by new power generation when local labor is used to install equipment and operate the new energy-generating facility.

Results in all three states show that adding wind facilities will provide a greater economic benefit to the state economy, due in large part to payments for property taxes. Wind pays a proportionally larger share in property taxes because more facilities must be erected to generate equivalent power. Below are state-specific results. Some notable differences are:

- Prices for fossil fuels are assumed to be higher in Michigan than in the other states, and capacity factors are lower. This leads to an increase in overall capacity needed and in dollars spent in Michigan.
- Based on actual data for proposed new plants, installed cost for a coal plant is much higher in Arizona (\$2000/kW) than in Colorado (\$1450/kW), which makes a considerable difference. Coal benefits Arizona’s economy more than Colorado’s. This could be due to varying pressures for new environmental equipment or state policies.

- Even though a state may not have natural resources to generate electricity, if it has a large resource (coal or gas) transportation industry, like Michigan, the economy can benefit significantly from the imported resource.

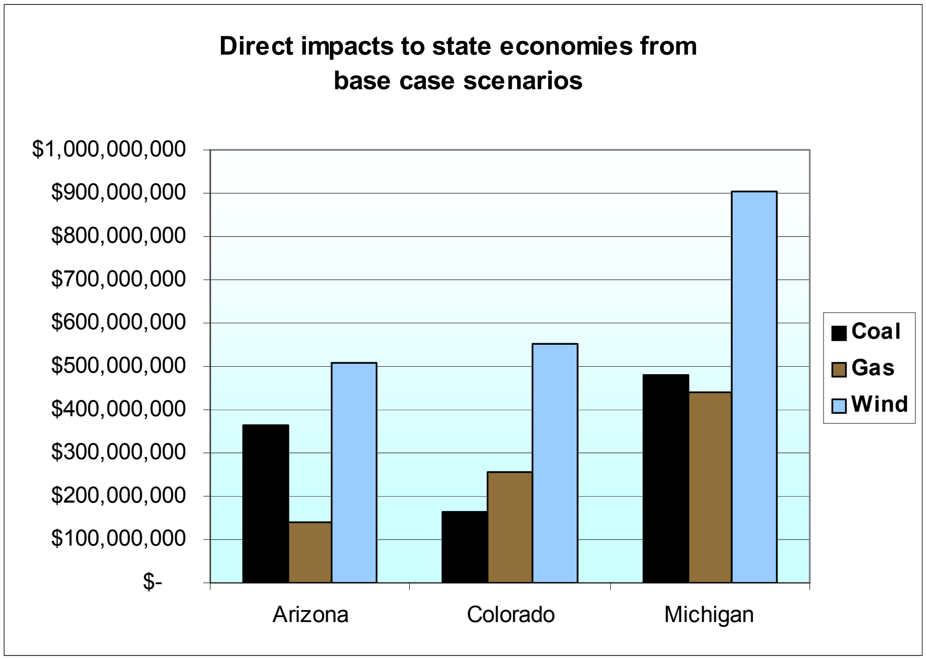


Figure 12. Base case scenarios of economic impact from new power plants in Arizona, Colorado, and Michigan

Individual State Results

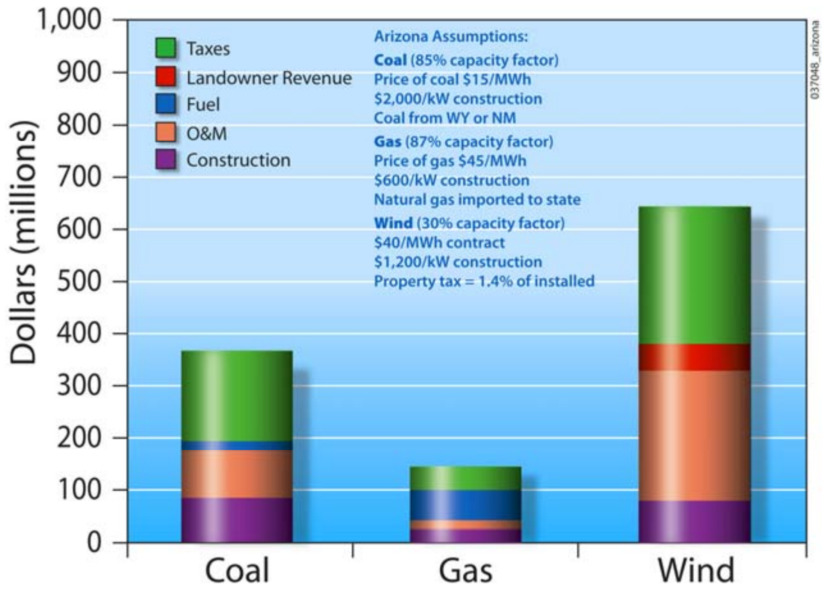


Figure 13. Dollars spent on new electricity generation from coal, gas, and wind in Arizona
Note: The fuel components for coal and natural gas are prices paid by the power plant for fuel. The contract price listed for wind is the amount the plant owner can charge for the output of the wind farm and is used to calculate landowner revenue.

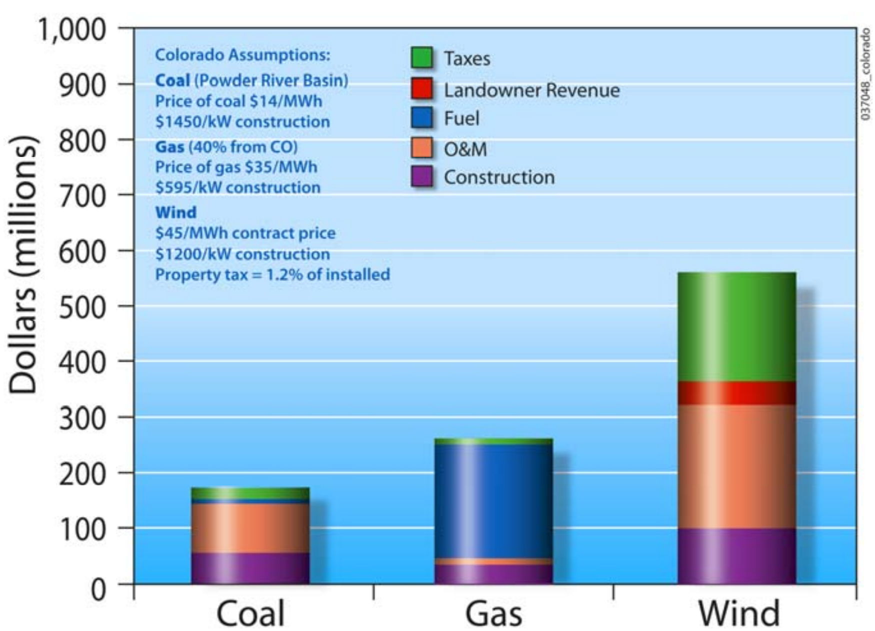


Figure 14. Dollars spent on new electricity generation from coal, gas, and wind in Colorado

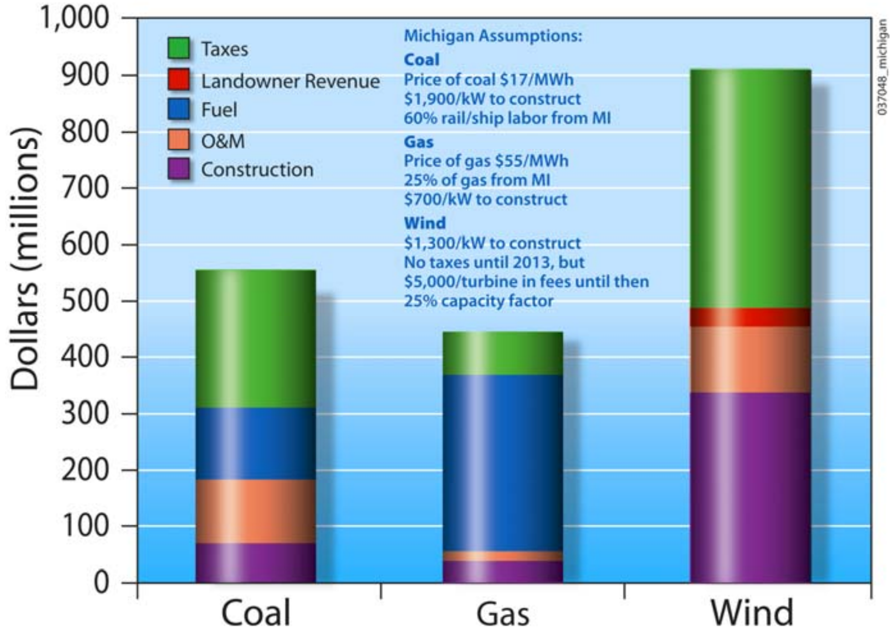


Figure 15. Dollars spent on new electricity generation from coal, gas, and wind in Michigan

Colorado Results and Specific Sensitivities

As Figure 14 and Table 2 indicate, the average wind plant would bring more dollars to the Colorado economy than coal or gas plants, provided that the wind plant hires some in-state labor and uses some Colorado materials (e.g., concrete). This result is partially due to the large percentage of in-state workers (20%-46%) for construction, the even larger percentage of workers during the operations phase (90% in state), and the size of the project (680 MW versus 270 MW or 280 MW). A large part of the wind spending is also due to county property taxes. In other states, wind plant owners have negotiated partial exemptions from taxes, but this has not occurred in Colorado. However, coal and gas plants have historically been at least partially exempt from property taxes.

Table 2. Dollars Spent in Colorado from 270 MW New Energy Output over 20 Years

	Coal	Gas	Wind
Construction	$47,705,000	$24,458,963	$91,392,000
O&M	$90,125,000	$11,054,118	$223,040,000
Fuel	$8,756,496	$210,442,575	$ -
Landowner Revenue	$ -	$ -	$43,500,000
Taxes	$17,271,121	$8,406,060	$193,228,800
* Construction times vary for each resource: coal 5 years, gas 2 years, wind 1 year			

When in-state versus out-of-state spending is calculated, it becomes apparent that a new gas plant would produce more total spending but that most of the money would be sent out of state. Each generating source spends more out of state than in Colorado, regardless of the fuel source or tax negotiation. Figure 16 shows in-state and out-of-state spending for new power generation. As previously noted, this project does not examine price impacts to consumers but considers overall state economies. Clearly, if consumers have to spend more of their income on electricity, they will have less to spend on other goods and services. When making an informed decision about new power generation, a policymaker should include consumer pricing and other issues, along with information from studies like this one.

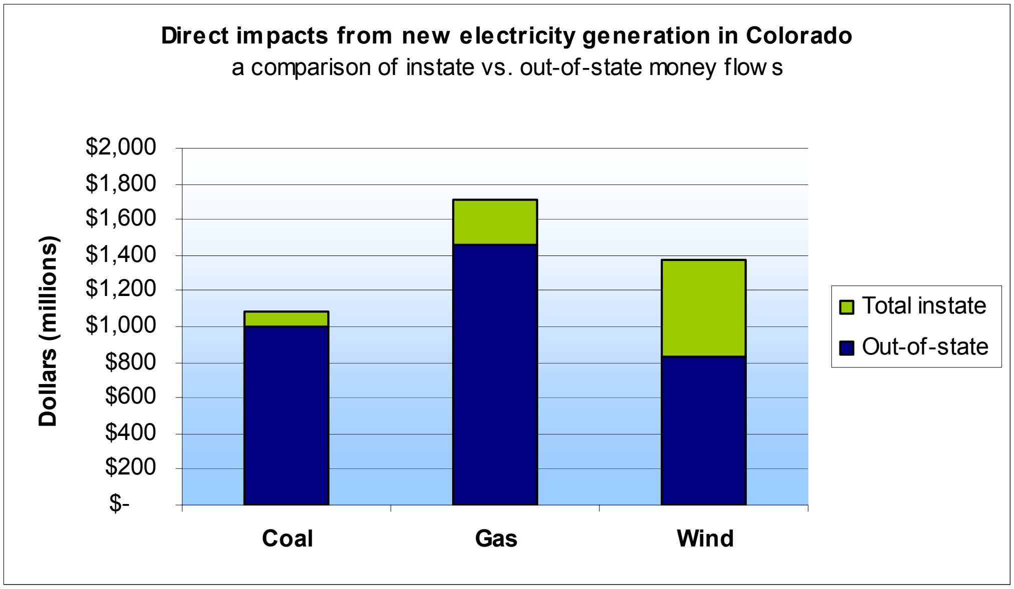


Figure 16. Colorado vs. out-of-state impacts from new electricity generation

The following series of figures and tables show individual energy-generation resources broken down by component for the Colorado economy. In a forthcoming publication, these figures will be presented for Arizona and Michigan and will be located in assumptions sections specific to each state. The figures show direct economic benefits to the economy from each resource, given the most likely scenario. I-shaped bars represent uncertainty ranges in the data. Further explanation of sensitivity analyses for particular energy resources may be found in Sensitivity Scenarios.

Table 3 and Figure 17 show direct economic benefits to Colorado for a coal plant with sensitivity bars. The biggest range of uncertainty is caused from the plant using Colorado coal, which is unlikely.

Table 3. Direct Economic Benefits from New Coal Generation

COAL		Range	% CO*	%CO range
Construction labor 25%	$1,450/kW	$1300 -$1800/kW	17%	7%-37%
Construction materials 75%	$1,450/kW	$1300 -$1800/kW	5%	0%-15%
O&M labor 65%-75%	$25/kW	$8 - $27/kW	65%	25%-95%
O&M materials 25%-35%	$25/kW	$8 - $27/kW	63%	60%-93%
Fuel	$14/MWh	$13 - $18/MWh	0%	0%-56%
Mining	40% of fuel	40% - 50%	0%	0%-56%
Railroad	60% of fuel	50% - 60%	10%	0%-10%

*Money spent in Colorado

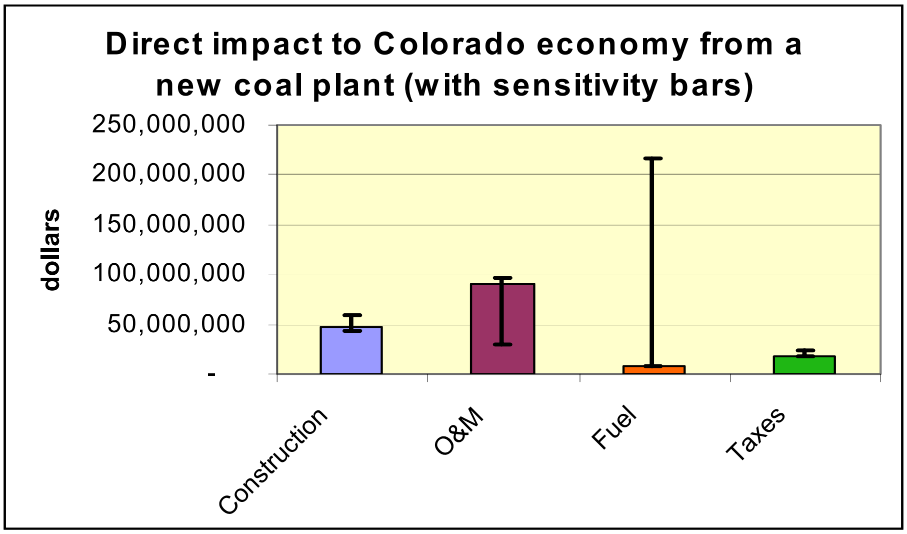


Figure 17. Direct impact to Colorado economy from a new coal plant, with uncertainty bars

As shown in Tables 4 and 5 and Figures 17 and 18, coal and gas have high uncertainty in their fuel categories. Almost all of the uncertainty for natural gas is related to gas price estimates. The price range is from $30/MWh to $55/MWh. Prices as high as the top scenario ($55/MWh) are unlikely but possible in Colorado power plants' long-term contracts. Coal's uncertainty bar has such a large range because of the chance that 100% of the coal may come from Colorado, as opposed to the assumed 0%.

Table 4. Direct Economic Benefits from New Natural Gas Generation

GAS		Range	% CO*	Range % CO
Construction labor 25%	$595/kW	$550-$800/kW	40%	15%-60%
Construction materials 75%	$595/kW	$550-$800/kW	5%	0%-10%
O&M labor 75%	$10/kW	$8-$19/kW	25%	16%-45%
O&M materials 25%	$10/kW	$8-$19/kW	5%	10%-45%
Fuel	$35/MWh	$30-$55/MWh	40%	10%-66%
Extraction	80% of fuel	-	15%	5%-20%
Pipeline	20% of fuel	-	0%	0%-10%

*Money spent in Colorado

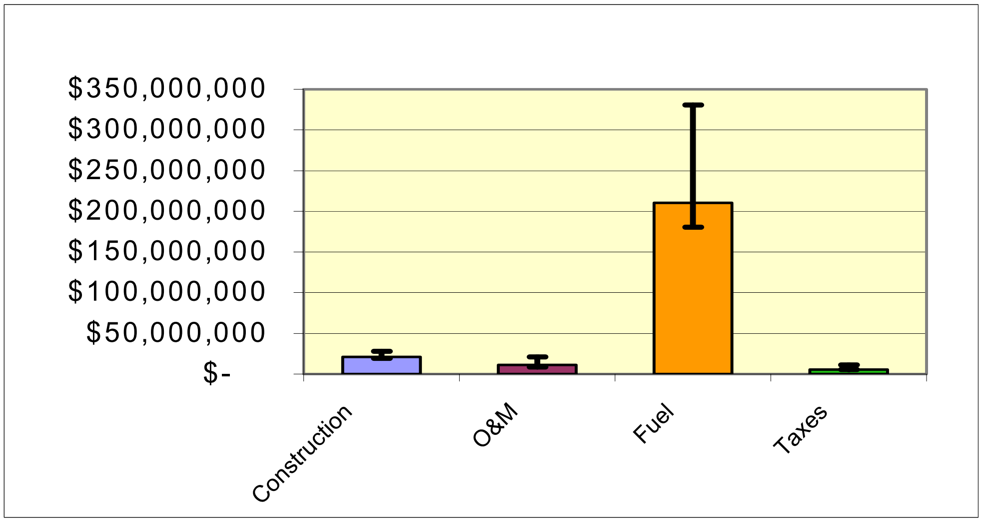


Figure 18. Spending in Colorado for a new natural gas plant, with uncertainty bars

Table 5. Direct Economic Benefits from New Wind Generation (635 1.5-MW turbines)

Wind		Range	% CO*	Range % CO
Construction labor 10%	$1,200/kW	$1100-$1500	40%	20%-46%
Construction materials 90%	$1,200/kW	$1100-$1500	8%	6%-10%
O&M labor 70%	$20/kW	$10-$27/kW	90%	80%-99%
O&M materials 30%	$20/kW	$10-$27/kW	20%	5%-33%
Landowner revenue	3.5% of revenue	$3000-$5,000	100%	-
Property taxes	1.2% of project	0.9% - 3%	100%	-

*Money spent in Colorado

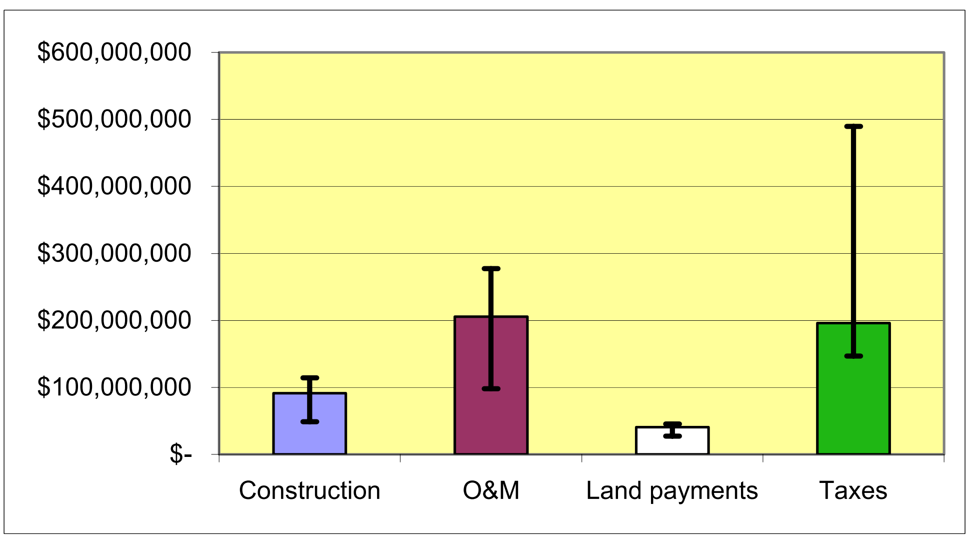


Figure 19. Spending in Colorado for a new wind power plant, with uncertainty bars

Table 5 and Figure 19 show direct economic impacts for building new wind power. For wind, the component with the most uncertainty is taxes. Typically, taxes are assumed to be between 0.9% and 3% of total installed costs. The large range in dollars per kilowatt for construction between $1100 and $1500, along with the property tax percentage, leads to the sizable range in construction results. O&M is considered by some developers to be 60% labor and 40% parts, while most consider that the labor accounts for between 70%-80%. Landowner revenue can fluctuate between $3,000 and $5,000 per turbine per year (based on the assumed 1.5-MW turbine size).

The data show significant differences and implications between wind and fossil fuels in the category of property taxes in all states. Coal and gas plants owned by utilities are often but not always exempt from property taxes in Colorado, and the utility might negotiate a deal with local communities by paying for county improvements such as a library, school, or police station. Such negotiated costs cannot be captured in a study of average power plant benefits because they are unique to each deal made between the utility and county. It should be noted that these negotiated donations from utilities would also benefit communities and, therefore, the Colorado economy. The County presumably finds the short-term gain of the payment, in addition to jobs created by the new power plant, worth the exchange for property taxes. However, the utility makes a one-time payment to the county, whereas property taxes would be collected over the lifetime of a power plant.

In addition to the consideration of tax exemption, wind plants purchase or lease a considerably larger piece of property for the same energy output as gas and coal. The State of Colorado does not base property taxes on the actual amount of space utilized by wind turbines but by the value of the installed turbines. The installed turbine value is greater than the value of a gas or coal plant because so many wind turbines are needed to generate the same amount of electricity. This is significant in rural communities because the county divides tax revenues to pay for services such as schools and roads. Wind plants also cause an increase in a landowner's property values.

Sensitivity Analyses

Following is an exploration of some uncertainty scenarios or sensitivity analyses discussed above. In the most likely scenario, coal for a new Colorado coal plant will come from Wyoming. Figure 20 shows a scenario in which all of the coal comes from Colorado. With everything else remaining equal, coal will not bring as much spending to Colorado as wind (but more than gas), and spending will be significantly higher than it is with out-of-state coal.

As mentioned, another uncertainty is the origin of Colorado's natural gas plants. At the highest, according to most natural gas experts we spoke with, 66% of the natural gas will come from Colorado. With everything else remaining in the base case, here are the results for a higher percentage of gas from within the state.

We mentioned the differences between results without an applied discount rate and a discount rate of 5% or 7%. In Figures 22 and 23 below, we see the results for Colorado coal. In forthcoming versions of this paper, we will display other components and resources with applied discount rates. When a discount rate is applied, the impacts are naturally smaller.

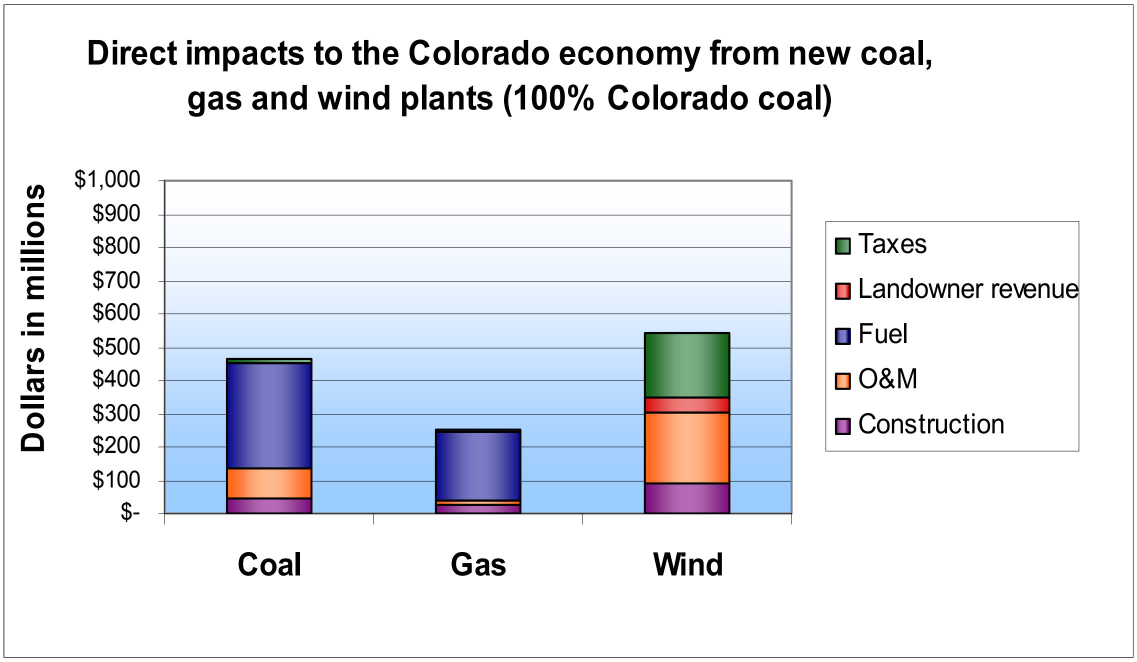


Figure 20. Sensitivity scenario: 100% of coal is from Colorado mines

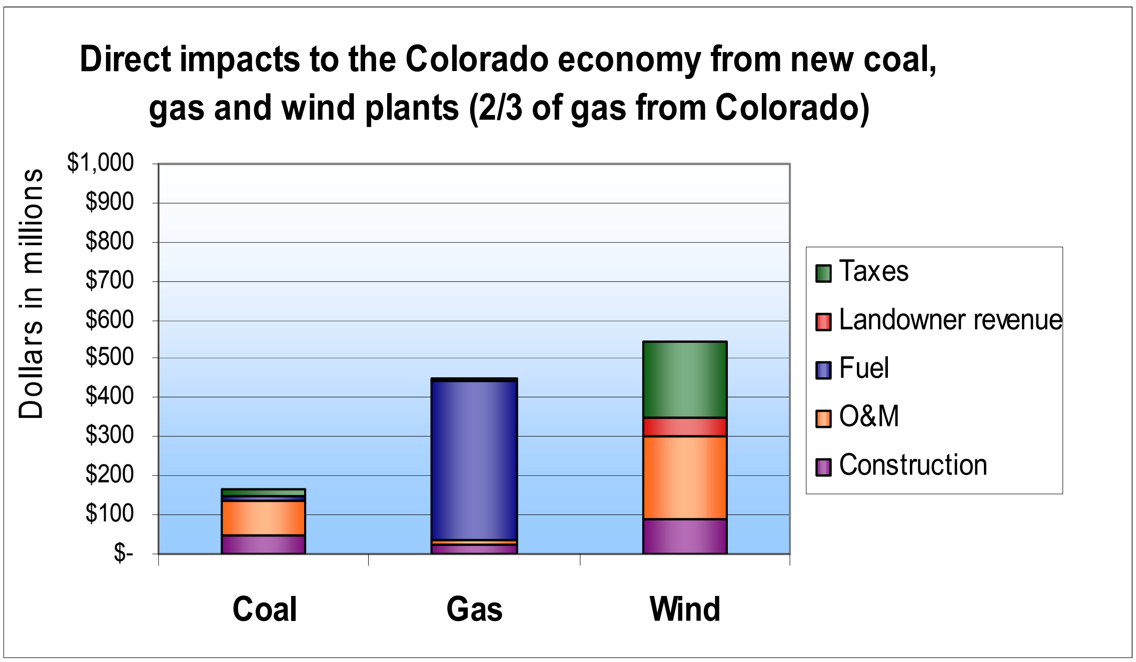


Figure 21. Sensitivity scenario: 66% of natural gas is from Colorado

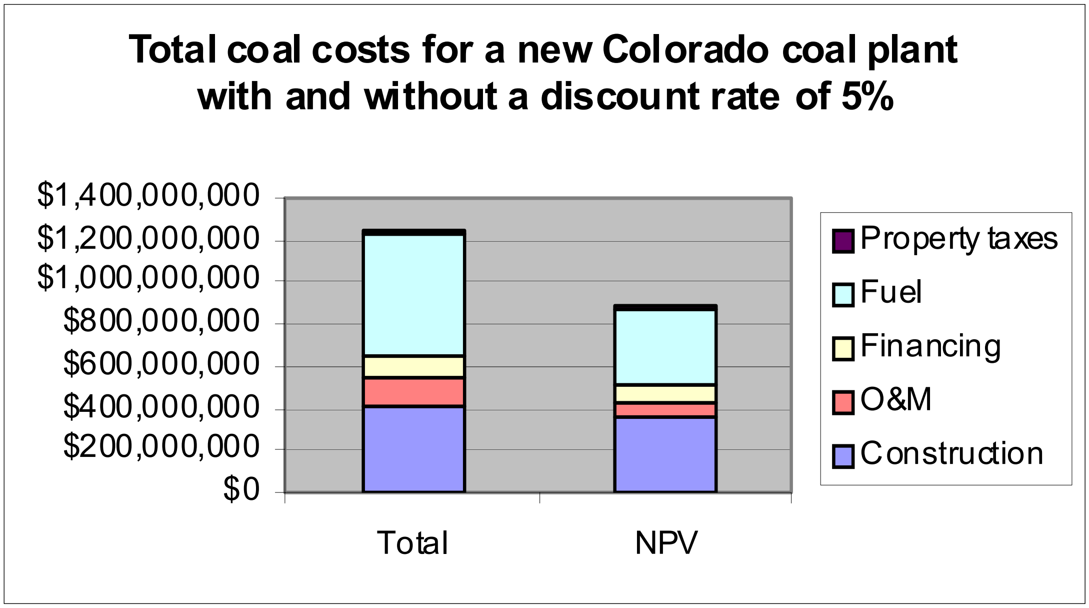


Figure 22. Total impacts (in and out-of-state) for a new Colorado coal plant, with and without a discount rate of 5%

Note that construction and financing in both cases remain relatively unchanged because construction occurs within the first 5 years, and we assume 10 years for financing.

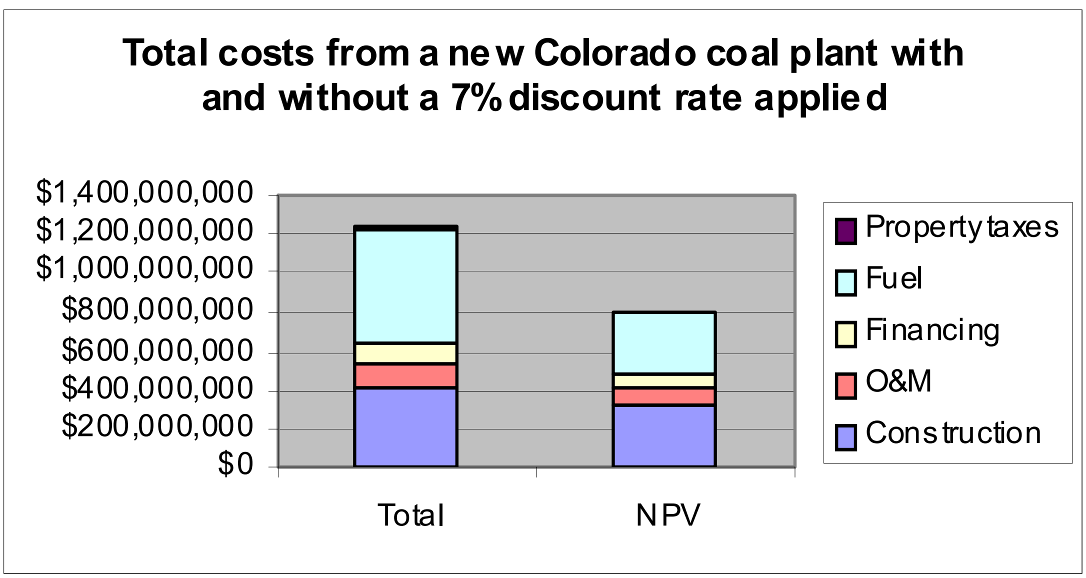


Figure 23. Total impacts (in-state and out-of-state) for a new Colorado coal plant, with and without a discount rate of 7%

Lessons Learned

When conducting a "follow the money" study in other regions, it will be helpful to draw on lessons from this report to save time and frustration for researchers and interviewees. Methods detailed here are transferable to other projects that explore economic questions about which energy resource to build next.

As with any research project, the first step is to define the required data and obtain contacts for that information. Local data are almost always preferred, but when it is not available, national averages may be sufficient. For example, is it important to have precise railroad data for your state, or can you use national averages? We carefully chose components of this research and selected the most economically significant benefits to represent graphically. Unfortunately, many developers consider this type of information proprietary due to competitive forces in the marketplace. Many costs and benefits of electricity generation are proprietary and cannot be released. Some dollar values for this project were indeed confidential and were given to us with the understanding that we would use aggregate numbers and not mention sources.

Information for labor and equipment costs was obtained through much deliberation from key industry contacts. In addition, we used JEDI (Goldberg et al. 2004), which was especially helpful for cost breakdowns. For overall costs of fuel and O&M, we referred to power plant operating companies and BaseCase. For specific numbers, such as the labor component of natural gas transport, we spoke with industry representatives (e.g., natural gas pipeline manufacturers). We obtained manufacturer names by speaking with people at existing utility power plants. We did not add environmental or political costs and benefits, which would be much harder to quantify than direct economic benefits. We recommend including only operations and maintenance costs – not including “all-in,” or costs such as taxes or landowner revenues, which should be broken out separately.

To obtain financing information, we initially contacted utility employees, who were generally unable to answer our requests. Eventually, we learned from other energy experts that financing for all three power sources is most likely an out-of-state impact, with no money flowing into the Colorado economy. Some small wind projects may be financed in-state, but usually financing comes from out of state, unless the plants in question were in New York or Massachusetts, where large lending institutions are located. We recommend contacting in-state independent banking associations. These organizations may know about power plant financing. Additionally, municipalities and electricity cooperatives might have helpful information and/or contacts. See the Components section of this report for other financing options.

Tax information should be sought first from counties, which is where most property tax is collected. Obtain mill levies and the procedure by which property taxes are assessed. If county taxes are assessed by the State, researchers will likely need to combine information from state assessors with details from county assessors and treasurers. The Public Utilities Commissions, in this case, did not provide data for any categories analyzed by this project, but we do recommend interviewing them in case they are able and willing to help. Researchers working with the Public Service Commission in Michigan, for example, were extremely helpful.

It is important to remain “resource neutral” when interviewing so that all parties feel comfortable providing information. It is also crucial to state assumptions early, so that they are clear in the project results. More important, stating assumptions early will ensure that they are clear to researchers throughout the project. Project boundaries and scope are closely linked to assumptions.

Conclusion

The addition of a new generating facility equivalent to a 270-MW natural gas plant will have direct economic benefits for a state's economy. If the fuel of choice is coal or gas, impacts to the economy may be fewer from coal or gas than if the fuel is wind. But natural gas also has a significant impact to the economy if a portion of the natural gas comes from within the state and is transported by state industry. If a big portion of the labor for coal extraction or coal transportation comes from within the state, then coal will bring significant spending to the state (however, according to our assumptions, not as much as wind power would bring for the equivalent amount of energy produced).

Energy planners and the energy industry should consider studies like this when deciding where to site a power plant and which benefits can be offered to local communities from the addition of a new power plant. This information is also valuable in making state- or regional-level policy decisions about energy resources and state-sponsored incentives, such as renewable portfolio standards or energy incentives.

Additional research is needed on this topic, especially on county and state taxes and on project financing. It is likely that tax impacts are so specific to each case that they will have to be evaluated on a case-by-case basis. This study did not include externalities such as air pollution, effects to the local environment, or payments to the state for black lung disease. Another study might include such costs. Future work might also address the difference in consumer rate impacts associated with different plants.

Acknowledgments

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Personal Communication

Some personal communication for this research is considered confidential. Agencies, companies, and organizations allowed the author to use their data in aggregate only. In some cases, the author is able to list company or organization names, but not employee names. Personal communication for this project included data and advice from the following:

Andy Wyatt, Prowers County Assessor
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Basin Electric Power Cooperative
Boulder County Treasurer's Office
Colorado Mining Association
Colorado Oil and Gas Commission
Colorado Rural Electric Association
Craig Cox
Dale Osborn, DISGEN Systems
Energy Intelligence Group, Inc. for pipeline capacity information
EnXco, Inc.
La Plata County Assessor's and Treasurer's Offices
Mark Walker, State Division of Taxation
Marshall Goldberg, MRG & Associates
Michael Milligan, National Renewable Energy Laboratory
Deb Meyer, Colorado Office of Taxation, State Division of Property Taxation
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Prowers County Assessor's Office
Ryan Wiser, Lawrence Berkeley Laboratories
Steve Clemmer, Union of Concerned Scientists
Susan Innis, Western Resource Advocates
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14. ABSTRACT *(Maximum 200 Words)*
With increasing concerns about energy independence, job outsourcing, and risks of global climate change, it is important for policy makers to understand all impacts from their decisions about energy resources. This paper assesses one aspect of the impacts: direct economic effects. The paper compares impacts to states from equivalent new electrical generation from wind, natural gas, and coal. Economic impacts include materials and labor for construction, operations, maintenance, fuel extraction, and fuel transport, as well as project financing, property tax, and landowner revenues. We examine spending on plant construction during construction years, in addition to all other operational expenditures over a 20-year span. Initial results indicate that adding new wind power can be more economically effective than adding new gas or coal power and that a higher percentage of dollars spent on coal and gas will leave the state. For this report, we interviewed industry representatives and energy experts, in addition to consulting government documents, models, and existing literature. The methodology for this research can be adapted to other contexts for determining economic effects of new power generation in other states and regions.

15. SUBJECT TERMS
wind energy; economic development; economic impacts; coal; natural gas; Arizona; Michigan; Colorado; power plants

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Strong Winds

Opportunities for rural economic development blow across Nebraska

STEVEN CLEMMER

Union of Concerned Scientists

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February 2001

Steven Clemmer is a senior analyst in the UCS Clean Energy Program.

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Executive Summary

In recent years, wind power development and use has expanded rapidly in the United States and around the world. This trend is expected to continue, especially in the Midwest. While Nebraska has among the best wind energy resources in the nation, the state currently lags behind its neighbors in developing wind power.

The Union of Concerned Scientists analyzed the potential economic benefits and costs of expanding wind power in Nebraska. We found that the total net benefits to the state economy of developing wind power instead of coal and natural gas are nearly $15 million per year over a 20-year period. We based our analysis on a policy goal of generating 10 percent of Nebraska's electricity from wind power by the year 2012. This policy goal is achieved through the implementation of a renewable portfolio standard (RPS). An RPS requires electricity suppliers to sell a set amount of renewable energy to their customers. Meeting the 10 percent goal would result in 800 megawatts of wind capacity installed in the state by 2012.

New jobs and economic activity would be created directly from building, operating, and maintaining wind facilities, as well as indirectly from local business supplying goods and services to support those activities. We found that developing 800 megawatts of wind capacity would, on net, create more jobs, earnings, and growth in gross state product than developing natural gas and coal facilities to produce an equivalent amount of electricity. For example, in 2012, the year the RPS goal is reached, there are 360 more jobs, $8 million more in earnings, and $35 million more in gross state product. We found that wind projects generate roughly 2.4 times more jobs during construction and 1.5 times more jobs from ongoing operation and maintenance than do coal and natural gas plants.

Making a long-term commitment to develop wind power could help spur development and expansion of businesses that manufacture wind turbines and related components in Nebraska. We found that if half of the turbines and related components and all of the towers that are needed to meet the 10 percent goal were manufactured in Nebraska, an additional 250 jobs, $15 million in earnings, and $44 million in gross state product would be supported each year over the 10-year period. Additional jobs and economic activity that could result from exporting equipment to other states are not included in these estimates.

The analysis shows that wind power could be an important source of rural economic development in Nebraska. We found that farmers and landowners would be receiving $2.2 million in lease payments by 2012, assuming $2,000 per year for each wind turbine installed on their land. Wind projects could also generate property tax revenues worth an estimated $5.2 million by 2012, assuming private developers own half of the projects.

These benefits are most likely to accrue to the areas of the state that need them the most. Median income levels in Nebraska's ten windiest counties are, on average, 21 percent below the state average, and poverty rates are higher than the state average in all but one of the windiest counties. Moreover, while the state's population is projected to grow 14 percent between 1990 and 2010, population in the ten windiest counties is projected to decline by

9 percent on average during the same period. This problem is particularly severe in Sheridan, Keya Paha, and Scotts Bluff counties, where the population is projected to decline by 20 to 25 percent. The economic opportunity that wind power development provides has the potential to offset this trend.

The two most important variables affecting the cost of wind power are ownership and the availability of federal incentives. Our base case scenario assumed that Nebraska's public utilities would own half of the projects and private developers would own the other half, and that federal incentives for wind power are available through 2006. Under this scenario, we estimated that generating 10 percent of the state's electricity with wind power instead of coal and natural gas would cost an additional $3.5 million per year over a 20-year period or roughly 7 cents per month on a typical household electric bill (using 500 kWh per month).

Under a high-cost scenario in which private developers own all of the projects and federal incentives are not available, the typical household would pay an extra 59 cents per month in 2012. Under a low-cost scenario in which Nebraska's public utilities owned all of the projects and federal incentives are available through 2006, the typical household would save about 20 cents per month in 2012.

By taking advantage of its as yet untapped wind resources, Nebraska will be taking an important step toward reducing its reliance on expensive, aging nuclear power plants and dirty coal plants that pollute the air and jeopardize the health of all Nebraskans. By starting on this path now, the people of Nebraska can prepare themselves for the expected shortfall in electricity generating capacity by relying on a clean source of power that is not subject to the volatility of fuel markets.

Nebraska has a powerful opportunity to become a national leader in wind energy development just as it has with ethanol production. States like Iowa, Minnesota, and Texas are demonstrating that progressive state policies are key to fostering the growth of wind power. This report shows that Nebraska can make a significant commitment to develop wind power and maintain its low electricity rates, while providing net benefits to the state's economy and environment. Implementing a renewable portfolio standard in Nebraska could help spur development of new industries, offer a new cash crop to farmers, and provide an important source of jobs and income to rural communities.

Introduction

The wind power industry is expanding rapidly all over the world. With an average annual growth rate of 32 percent since 1995, wind power is the fastest growing energy source on the planet. In 2000, new wind power investments reached $4.6 billion. By 2004, global wind capacity is projected to more than triple, and new wind power investments are projected to rise to $7.6 billion.[1]

Wind power is also booming in the United States. Between June 1998 and June 1999, nearly $1 billion in wind turbines were installed in the United States—enough to power over 400,000 homes. US wind capacity is expected to double by the end of 2001, providing an estimated $2.5 billion in new investment.[2] While wind power currently provides 0.1 percent of the country's power, the Department of Energy's "Wind Powering America" initiative has set a goal of producing 5 percent of the nation's electricity from wind by 2020. DOE projects to achieve this goal will add $60 billion in capital investment in rural America, provide $1.2 billion in new income for farmers and rural landowners, and create 80,000 new jobs during the next 20 years.

Until recently, wind power was concentrated in California. Now large-scale turbines can be found in more than half of the states. Farming regions in Minnesota and Iowa have emerged as major wind power growth areas, followed by Texas, Wyoming, Colorado, and Wisconsin. By the end of the year, the Northwest and Nevada will be home to the world's two largest wind projects.[3] State and federal policies have been the main driver for wind development in most states. Wind power is also growing as a result of technology improvements, cost reductions, high natural gas prices, and environmental concerns.

Nebraska has some of the best wind resources in the country. Yet it is lagging far behind its neighbors in developing wind power. So far, only four large wind turbines have been built in the state, providing 0.03 percent of its electricity. Moreover, Nebraska has not made a significant future commitment to harness its wind potential.

Electricity generation in Nebraska is dominated by large coal and nuclear plants, which produce enormous environmental and public health effects and risks. Coal is responsible for a host of ills, including acid rain, smog, global warming, and mercury contamination of lakes. In 1998, Nebraska spent about $113 million on imported coal to produce 64 percent of the electricity generated in the state, exporting dollars and jobs in the process.

In 1998, nuclear plants produced 29 percent of the electricity generated in Nebraska. Nuclear plants produce tons of highly radioactive waste, which must be stored safely for tens of thousands of years. But nuclear power is slowly declining, mostly due to economic and safety

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[1] BTM Consult ApS, online at *www.btm.dk/overheads/wmu99/sld001.htm.*

[2] Brian Parsons, National Renewable Energy Laboratory, presentation at the *Harvesting Clean Energy* Conference, Spokane, WA, January 29, 2001.

[3] See "New Wind Plants in Northwest, Nevada to be World's Largest," American Wind Energy Association, January 25, 2001, online at *www.awea.org/news/news010125nwn.html.*

problems. A 1997 study listed Nebraska's Cooper and Fort Calhoun plants as among the *least* competitive plants in the country.[4]

Unlike other parts of the country, Nebraska has sufficient electricity generating capacity to meet its needs. In fact, Nebraska is a net exporter of electricity. However, as the demand for electricity continues to grow and as the state's aging coal and nuclear plants approach retirement, new electricity supplies will be needed to provide clean, reliable and affordable power.

> Until recently, few had mentioned Nebraska's wind resources as a way to grow the state's economy, and provide solid benefits to ag producers. Once I started looking at the numbers and what other states are doing, I think we may have a tremendous opportunity to build a new export industry just as we've done with ethanol…The regional wind-to-electricity story is not much different from the development of Nebraska's ethanol plants. We were far behind other states in ethanol production, but in six years we moved from an also-ran to a national leader in ethanol production because we established state policies and incentives that made converting corn to ethanol a state economic development goal.
>
> — Excerpts from Governor Johanns' welcoming remarks at the Nebraska Wind Energy Forum in Lincoln, September 20, 2000.

Nebraska's 1997–2016 Integrated Resource Plan indicates that the state could face a generating capacity shortfall as early as 2005, when the contract with out-of-state utilities for a share of Cooper Nuclear Station's power expires.[5] Assuming the contract is renewed or the power is sold to another electricity provider, the report indicates that the state could still face a capacity shortfall by 2008. The deficit grows to nearly 1,600 megawatts (MW) or 25 percent of the state's electricity needs by 2014, when the plant is scheduled to retire. A report by the North American Electricity Reliability Council (NERC) predicts that the regional power pool that includes Nebraska may need over 5,000 MW of new generating capacity by 2006, which is about the total amount of electricity capacity currently used in Nebraska.[6]

Nebraska is facing an important choice. It can continue to rely on imported fossil fuels and expensive, aging nuclear plants, or it can invest in wind power and other clean homegrown renewable electricity resources. Given Nebraska's enormous wind and biomass resources, the state could generate enough power to meet a significant portion of its own needs and could export power from these resources to other states as well.

Beyond meeting its energy supply needs, wind power could provide an important boost for Nebraska's economy. Nebraska's best wind resources are generally located in rural areas that could benefit from new jobs and income. In September 2000, at the Nebraska Wind Energy Forum in Lincoln, Governor Johanns suggested that wind power could provide a new opportunity to grow the state's economy, just as ethanol production has done (see box). He noted that state policies had been instrumental in making Nebraska a national leader in ethanol production.

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[4] Washington International Energy Group, *Nuclear Power Plants and Implications of Early Shutdowns for Natural Gas Demand*, January 1997.

[5] Nebraska Power Association, *Statewide Integrated Resource Planning Coordination Report (1997–2016)*, October 1996.

[6] NERC 1999–2008 Reliability Assessment at page 71.

Wind power is already stimulating economic development in several states. For example, wind developers are paying farmers and landowners in Iowa and Minnesota about $2,000 per year for each turbine installed on their land. These royalty payments can provide a stable supplement to a farmer's income, helping to counteract the swings in commodity prices. Wind development is also creating new jobs in manufacturing, construction, operation, and maintenance of wind turbines. In addition, private wind development is providing an important source of tax revenue for many rural communities.

In this report, the Union of Concerned Scientists estimates the cost and potential economic benefits of developing wind power in Nebraska. The impacts are based on generating 10 percent of Nebraska's electricity from wind power by 2012, as proposed in a bill introduced in the Nebraska Legislature on January 16, 2001, by Senator Preister (LB 645). In addition to estimating the potential statewide economic impacts of wind development, we also identify the areas of the state that are most likely to benefit from wind development. Finally, we highlight some of the economic benefits of wind development in other states that have adopted policies to promote wind power.

Wind Power Development in the United States

Several factors are fueling the growth of wind power in the United States. Among these are technology improvements, declining cost, environmental and public health concerns, utility green pricing, and federal incentives.

Since 1980, the cost of wind power has fallen by 80 to 90 percent, as a result of technology improvements and economies of scale in manufacturing and installation. Wind energy experts project that the cost will decline further in the future, as discussed later in the report.

While the cost of wind power is declining, the cost of natural gas—the fuel of choice for new power plants—has suddenly increased. Natural gas prices have doubled over the past year, while national spot market prices have quadrupled. Homeowners can expect to pay 70 percent more, on average, for gas this winter than they paid last year, and the increase in gas use for electricity generation will likely keep prices high for at least the next few years.[7]

In contrast, the cost of wind power is relatively stable and predictable over a long period of time. This is because most of the cost is in the initial capital investment, while the fuel (the wind) is free. An increasing number of electricity providers have become interested in purchasing wind power to provide insurance against volatile gas prices.

Environmental and public health concerns are also driving wind development growth. The electricity industry is the single largest source of air pollution in the United States. Power plants are responsible for over two-thirds of the sulfur dioxide emissions that produce acid rain, a quarter of the smog-forming emissions, 40 percent of the heat-trapping emissions that cause global warming. They are also the largest source of mercury emissions. One study found that by 2007, an estimated 30,000 people will die prematurely in the United States from coal plant soot.[8] In contrast, wind power does not produce air emissions, generate solid, toxic, or radioactive waste, or use water. Therefore, wind power can help reduce both the cost of health care and the cost of complying with environmental regulations. It can also provide insurance against more stringent environmental requirements in the future.

Some wind development has resulted from voluntary customer purchases of green power. More than 190 electric utilities in the United States are now offering a wind power product to their customers, supporting an estimated 60 MW of new development.[9] Lincoln Electric Systems' two large wind turbines are supported through a green-pricing program.

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[7] See Bradley Keoun, "U.S. Natural Gas Costs Seen Even Higher Next Winter, AGA Says" *Bloomberg News*, February 1, 2000; and EIA, *Short-term Energy Outlook*, December 2000, online at *www.eia.doe.gov*.

[8] Clean Air Task Force, *Death, Disease and Dirty Power: Mortality and Health Damage Due to Air Pollution from Power Plants*, November 2000, based on Abt Associates, "Health Impacts Analysis" report, online at *http://cta.policy.net/fact/mortality/mortalitystudy.vtml.*

[9] Ed Holt and Associates, "A Quick Overview of Utility Green Pricing Programs," presentation to the Nebraska Wind Energy Forum, Lincoln, Nebraska, September 20, 2000.

Federal policy has also provided an important stimulus for wind development. The federal production tax credit (PTC) and renewable energy production incentive (REPI) for public power provides 1.5 cents per kilowatt-hour (adjusted for inflation) for 10 years. The PTC and REPI were enacted to allow wind to compete on a more equal basis with fossil fuels and nuclear power, which continue to receive billions of dollars in federal subsidies each year. Nebraska public utilities are eligible to apply for REPI funds for any wind projects they develop.

State Policies and Wind Development

While these factors have contributed to the growth of wind power, the majority of US wind development has occurred in states that have adopted supportive policies and created long-term markets for renewable energy. In California, tax incentives and favorable long-term contracts for renewables led to the birth of the modern wind industry in the early 1980s.

In the past few years, several states have made new commitments to develop renewable energy. Twelve states have adopted minimum renewable electricity requirements. Fourteen states have adopted renewable electricity funds, totaling about $3.7 billion by 2012. We estimate that these new laws will, together, result in 8,550 MW of new renewable power between 1998 and 2012—an increase of 63 percent over 1997 levels—as well as supporting 7,800 MW of existing renewables.[10] This development will provide enough clean power to meet the entire electricity needs of 5.6 million homes and reduce carbon dioxide—the main greenhouse gas implicated in global warming—as much as taking 4 million cars off the road or planting 1.2 billion trees.

These new commitments have already led to large-scale wind development in Minnesota, Iowa, Wisconsin, and Texas. The policies adopted in those states are described below.

Minnesota. Minnesota is the second largest producer of wind power and the ninth windiest state in the nation. Minnesota's wind development stems from the 1994 "Prairie Island Settlement." The Minnesota Legislature passed a law allowing Xcel Energy (formerly Northern States Power) to temporarily store nuclear waste at its Prairie Island nuclear plant on the Mississippi River. In exchange, Xcel Energy was required to install or purchase 425 MW of wind power and 125 MW of biomass power by 2002 and an additional 400 MW of wind by 2012. Under the requirement, wind and biomass would provide about 5 percent of the state's electricity in 2012. In addition, the law requires Xcel to contribute $500,000 per year for each cask storing nuclear waste into a fund to support new renewable energy projects. The fund will eventually provide up to $8.5 million per year. To date, 272 MW of wind power has been installed in Minnesota and another 164 MW has been proposed or is under development.

Iowa. Iowa is the third largest producer of wind power and the tenth windiest state in the nation. Iowa's wind farm developments stem mostly from the Alternate Energy Production law of 1983. In an effort to promote development of local resources and to implement the federal Public Utility Regulatory Policy Act, the legislature required the state's investor-owned utilities to generate or purchase about 2 percent of their power from renewable resources. The utilities fought the law for almost 15 years, appealing to both the Iowa Supreme Court and the Federal

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[10] These figures are based on an update to Steve Clemmer, Ben Paulos and Alan Nogee, *Clean Power Surge: Ranking the States*, Union of Concerned Scientists, April 2000.

Energy Regulatory Commission before finally complying.[11] Two large projects near Storm Lake and Clear Lake totaling about 240 MW are supplying enough power to meet the needs of about 63,000 homes. While this development is sufficient to meet the utilities' requirement under the AEP law, two private wind developers are planning on building two new wind farms totaling 180 MW this year.[12] Developers have already made agreements with 40 landowners to lease space for the turbines.

Wisconsin. Wisconsin is the nation's seventh largest producer of wind power, despite being ranked eighteenth in terms of its wind energy potential. To address power shortages in the summer of 1998, the Wisconsin Legislature passed a law requiring utilities to develop more power plants, including 50 MW of new renewables. The four investor-owned utilities affected by the law relied mostly on wind power to meet their renewables requirement. In 1999, Wisconsin also adopted a renewable portfolio standard (RPS) and renewable energy fund under its Reliability 2000 legislation. The RPS requires every electric utility in the state to provide 2.2 percent of its electricity sales from renewable energy by 2011, which could lead to an estimated 300 MW of new renewables. The renewable energy fund will provide about $2.8 million through 2008 for customer-owned renewable energy technologies.

Texas. Texas is the fourth largest producer of wind power and has the second best wind resource potential in the United States. In 1999, Governor George W. Bush signed into law a RPS requiring 2,000 MW of new renewables by 2009. The RPS has led to a flurry of new wind development. Over 730 MW of new wind development is currently planned, adding to the 188 MW already operating. Texas officials have said that the goal may be reached seven years ahead of schedule and only two and a half years after the legislation was passed.[13]

Wind Power and Economic Development

Wind power is providing important economic benefits in a number of states. The direct economic benefits include new jobs and income from construction, operation and maintenance; manufacturing of wind turbines and related components; payments to landowners; and tax revenues. Examples of these benefits are discussed below. Indirect benefits also result as expenditures for and income from these activities ripple through the local economy. Other economic benefits can result from reducing energy imports, improving air quality, reducing health care costs, and increasing tourism.

Construction, Operation, and Maintenance Jobs. In Lake Benton, Minnesota, construction of over 200 MW of wind power over a two-year period employed about 150 construction workers, as well as 22 people to operate and maintain the plant. The facility is now the second largest employer in town, after the school district, according to Jim Nichols, Lake Benton's economic development director. Iowa's 240 MW of large-scale wind development created an estimated 200 short-term construction jobs and 40 long-term operation and maintenance jobs at an average wage of $16 per hour.

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[11] Bentham Paulos, "Light at the End of the Wind Tunnel in Iowa," *Windpower Monthly*, December 1999.

[12] "Energy Companies Plan 2 Wind Farms in Iowa," Associated Press, January 14, 2001.

[13] "Texas Utilities Power Ahead on Meeting Renewable Energy Goal," American Wind Energy Association press release, August 31, 2000, online at *www.awea.org*.

Manufacturing Jobs. The recent growth in wind development in the Midwest has attracted new businesses to the region to manufacture wind turbines and related components. For example, in 1999, LM Glasfiber, a Danish manufacturer of wind turbine blades, opened a plant in Grand Forks, North Dakota, that employs 130 local people at a starting salary of roughly $10 per hour with benefits.[14] The new jobs are equivalent to 20 percent of the total jobs in the state's lignite coal industry. NEG Micon, a Danish wind turbine manufacturer, recently opened a plant in Champaign, Illinois, that employs over 30 people. It also located its US headquarters in Rolling Meadows, Illinois.[15] In June 2000, Vestas, another Danish company and the world's leading manufacturer of wind turbines, announced plans to open their US headquarters and build their first American turbine manufacturing plant in Pueblo, Colorado. It would employ over 600 people.

A few businesses in Nebraska have already benefited from wind development. When Enron Wind built the two-turbine Springview project, they hired Daniels Manufacturing, a local family-owned metal fabricating business in Ainsworth that specializes in making farm implements, to design and fabricate custom parts for the towers. The design of the parts was so successful that Enron Wind subsequently offered Daniels a contract to make the parts for an additional 300 towers in Minnesota and Iowa.[16] Valmont Industries, a leading manufacturer of center-pivot irrigation systems headquartered in Omaha, was involved in the construction of some of the turbines in Iowa and Texas and recently began development of a new support structure for wind turbines.

Landowner Revenues. Wind developers typically pay landowners around $2,000 per year over a 30-year period for each turbine installed on their land, or roughly 2–3 percent of the project's annual revenue. Large wind turbines use only about a quarter acre of land, including access roads, so farmers can continue to plant crops and graze livestock right up to the base of the turbines. In a good year, it would take 20 acres of corn or 100 acres of rangeland to produce the same amount of income as a single wind turbine.[17] Iowa's wind farms are paying royalties to 115 landowners totaling $640,000 per year. At the Foote Creek wind facility in Carbon County, Wyoming (the heart of coal country), landowners receive $140,000 in lease payments annually.

Tax Revenues. Wind development can also generate significant property, sales, and income revenues for rural communities. For example, a 20 MW wind farm in Kewaunee County, Wisconsin, will result in annual property tax payments of $200,000 to the county, equivalent to 50 percent of their annual budget.[18] Iowa's wind farms are generating an estimated $2 million per year in property taxes. Wind developers typically pay 1–3 percent of the project's value annually in property taxes.[19] The extent to which wind power development in Nebraska would

[14] Sam Black, "130 Jobs Blow into GF," *Grand Forks Herald*, December 8, 1998.

[15] Peter Kendall, "High Tech Windmills Churning up Hope," *Chicago Tribune*, March 2, 1999.

[16] Nebraska Wind Energy Task Force Report to Governor Johanns, January 25, 2001.

[17] This assumes $100/acre for corn and $20/acre for producing beef on rangeland.

[18] Michael Vickerman, RENEW Wisconsin, personal communication, 1999.

[19] Matthew Brown and Johanna Woelfel, *Tax and Landowner Revenues from Wind Power Development*, National Conference of State Legislators, State Legislative Report, April 2000.

generate tax revenues will depend on whether the project is owned by public or private entities. This is discussed in more detail later in the report.

Net Economic Benefits. Several studies have shown that investments in wind and other renewable energy sources can generate more jobs and income than investments in conventional power plants. For example, the New York State Energy Research and Development Authority estimates wind energy produces 27 percent more jobs per kilowatt-hour than coal plants and 66 percent more jobs than natural gas plants. A 1995 study by the Wisconsin Energy Bureau found that investing in 800 MW of renewables (including 200 MW of wind) by 2010 would create 3,300 more jobs, $81 million in higher disposable income, and a $165 million increase in gross state product, compared with investing in coal and natural gas power plants.[20] The additional income from renewables is equivalent to a benefit of 2 cents per kilowatt-hour for the state.

[20]Steven Clemmer, Wisconsin Energy Bureau, *Fueling Wisconsin's Economy with Renewable Energy*, 1995.

Wind Power in Nebraska

Nebraska has four large-scale wind turbines currently operating in the state, representing 2.8 MW of capacity. Lincoln Electric Systems owns two 660 kW turbines near Lincoln, which are supported through a green-pricing program. The output from the first turbine was fully subscribed in about two months, leading LES to install a second turbine.[21] The Nebraska Public Power District and several other utilities are collaborating with the Electric Power Research Institute and the US Department of Energy (DOE) on a demonstration project near Springview, consisting of two 750 kW turbines.

Nebraska's installed wind capacity is modest considering the state's excellent wind resources and the progress made in other states. Nebraska is the sixth windiest state in the nation, according to a DOE study.[22] A 1993 study by the Union of Concerned Scientists, *Powering the Midwest*, found that Nebraska has sufficient wind resources to theoretically produce 26 times its 1998 electricity use, though transmission constraints would limit the potential far below this level.[23]

To better understand the state's wind potential, the Nebraska legislature, the Nebraska Power Association, and the state energy office reached an agreement in 1994 to complete a state wind resource assessment. During the next four years, data collected from eight sites around the state identified average wind speeds ranging from 14.4 to 16.4 miles per hour at 40 meters above the ground.[24] The results were largely consistent with the estimates made in *Powering the Midwest.* The sites with the best resources are located in the north-central part of the state near Valentine, Springview, and Stuart, and in the southwestern part of the state near Imperial. However, many other areas of the state are likely to have sufficient wind resources to support wind power development.

The Nebraska wind resource map developed in *Powering the Midwest* is shown in Figure 1, along with the wind monitoring sites. This map groups areas according to their predicted average annual wind speeds. Most utility-scale wind plants are being installed in class 4, 5, and above areas, but projected improvements in wind technology should make class 3 areas attractive in the future.[25] Smaller wind turbines for residential and farm applications are designed to run in lower class 2 and class 3 wind speeds.

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[21] Al J. Laukaitis,. "LES Harnesses Renewable Energy Blowin' in the Wind," *Lincoln Journal Star*, December 14, 1998.

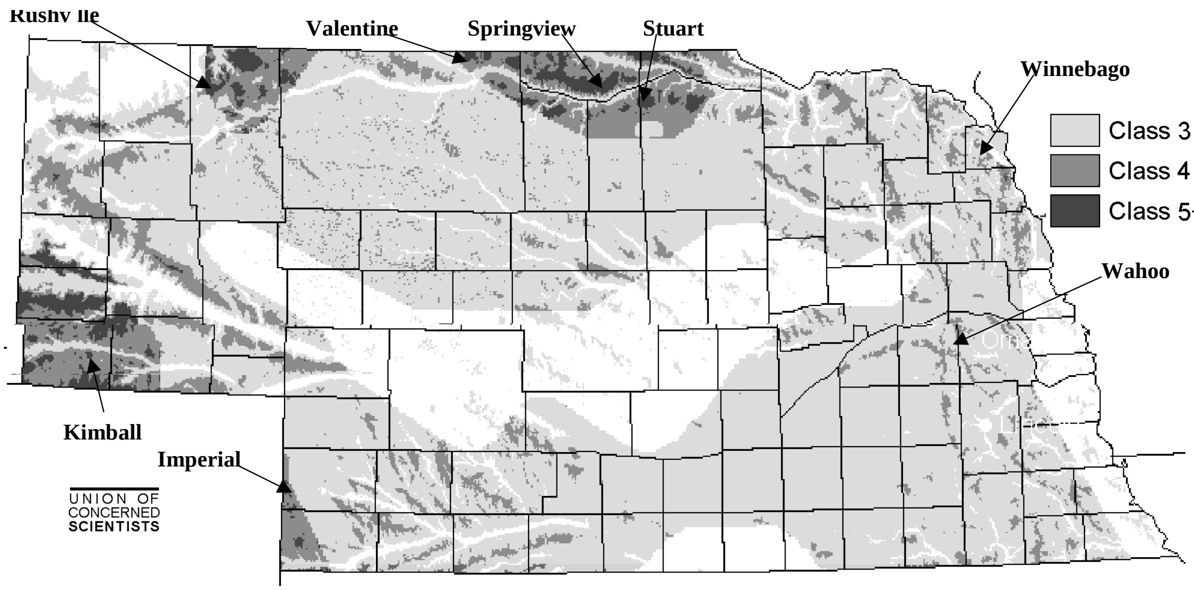
[22]D. L. Elliott, L. L. Wendell, and G. L. Gower, *An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States*, Northwest Laboratory, Richland, Washington, 1991, PNL-7789. Selected results from the study are available online at *www.eren.doe.gov/wind.*

[23] This is based on class 4 wind resources and higher. Michael Brower et al, *Powering the Midwest: Renewable Electricity for the Economy and the Environment*, Union of Concerned Scientists, 1993.

[24] *Nebraska Wind Energy Site Data Study: Final Report*, prepared by Global Energy Concepts, Inc. for the Nebraska Power Association, May 1999.

[25] Wind classes are defined by a range of wind power densities at a given height above the ground and relate to a range of wind speeds. Wind power density is expressed in watts per square meter of swept rotor area, or the area perpendicular to the wind flow. A class 5 wind class has a wind power density of 500–600 watts per square meter and reflects wind speeds of 16.8 to 17.9 miles per hour at 50 meters above the ground.

Figure 1. Nebraska's Wind Resources and Monitoring Sites



Source: UCS, Powering the Midwest, 1993.

Nebraska's best wind resources tend to be located in rural areas that are in need of new sources of jobs and income. For example, median income is 21 percent lower in the state's ten windiest counties (based on the UCS wind map) than the statewide average, as shown in Figure 2. The poverty rate is also higher than the state average in all but one of the state's most windy counties, as shown in Figure 3. In addition, while the state's population is projected to grow 14 percent between 1990 and 2010, population in the windy counties is projected to decline by 9 percent on average during the same period, as Figure 4 shows. This problem is particularly severe in Sheridan, Keya Paha, and Scotts Bluff counties, where the population is projected to decline by 20–25 percent.[26] New jobs and income from wind development could help keep people in the community.

[26] This information, which appears in the Nebraska Wind Energy Task Force's January 2001 report to Governor Johanns, was originally prepared by the author for a presentation given at Nebraska's Wind Energy Forum in Lincoln in September 2000.

Figure 2. Median Income in Nebraska's Most Windy Counties

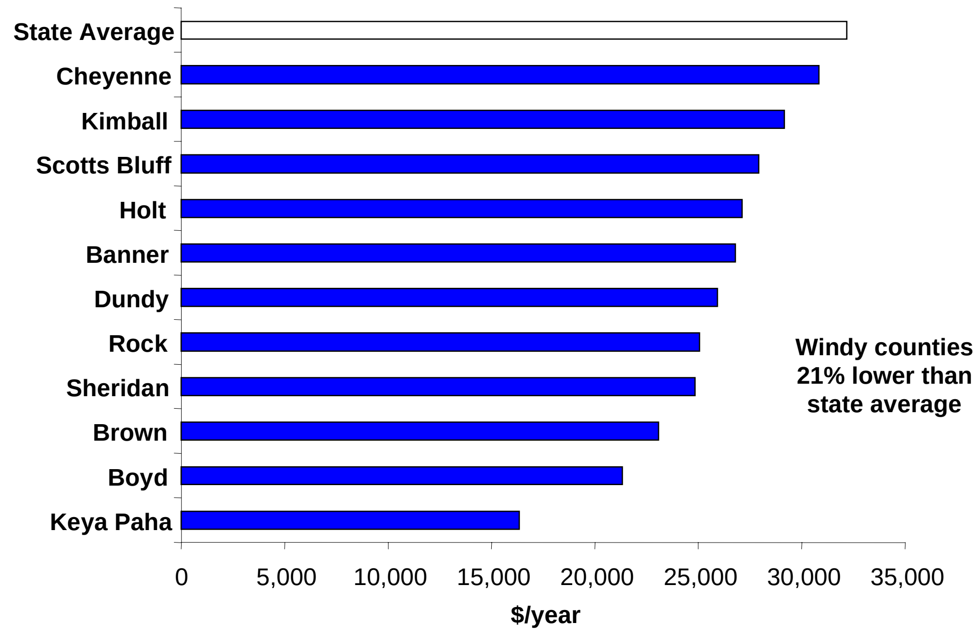


Figure 3. Poverty Rate in Nebraska's Most Windy Counties

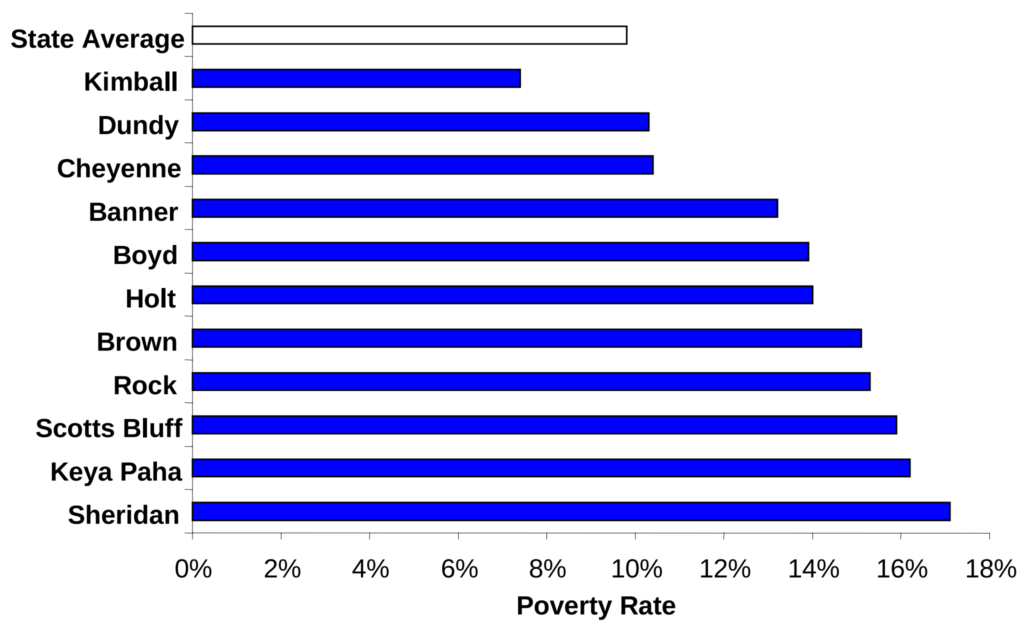
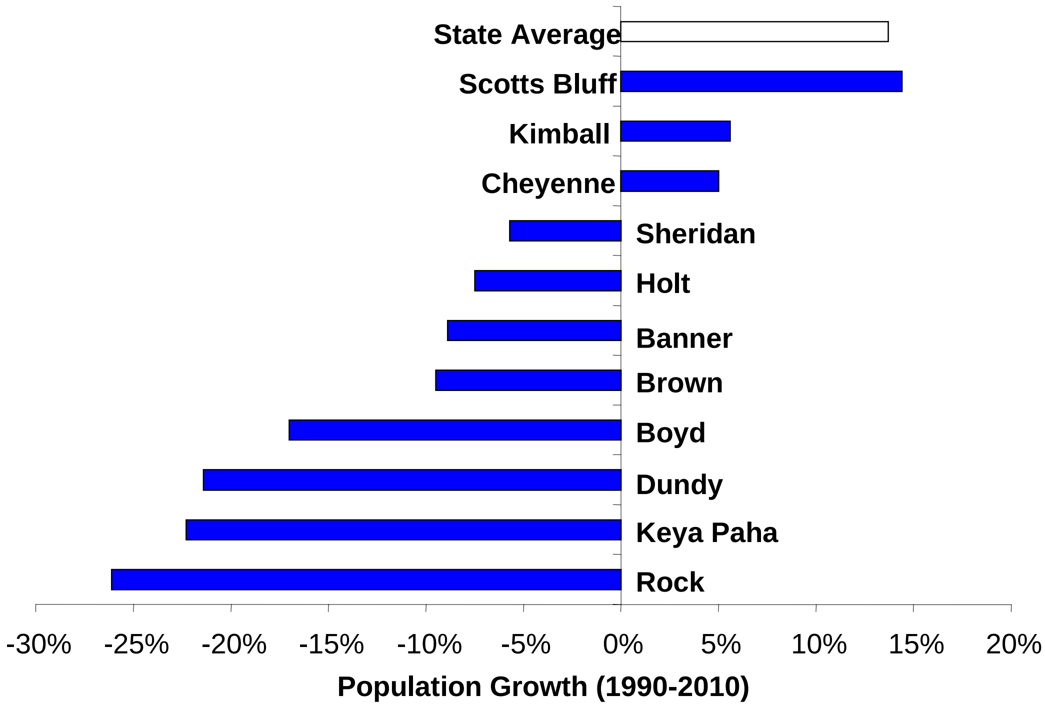


Figure 4. Population is Declining in Most Windy Counties, While the State Population Grows



Methodology and Assumptions

We estimated the potential economic impacts of developing wind power in Nebraska based on the following four steps. First, we calculated current and projected costs of developing wind power in Nebraska. Second, we estimated the market value or "avoided costs" of developing wind power in Nebraska, based on the conventional generation wind power would displace. Third, we calculated the total cost and displacement effects of producing 10 percent of the electricity used in Nebraska with wind power by 2012 to meet the RPS proposed in LB 645. Finally, we applied the expenditures for wind and conventional generating technologies to an input-output model of Nebraska's economy to calculate economic impacts. Each of these steps is described in more detail below.

Wind Power Costs in Nebraska

The cost of developing wind power in Nebraska will depend on several variables, including the size and ownership of projects, financing costs, and the availability of federal incentives and excess transmission capacity. Our assumptions for capital and operation and maintenance costs, capacity factor, federal incentives, transmission costs, ownership and financing, and property taxes are discussed below and summarized in Table 1.

Capital and Operation and Maintenance Costs. Our assumptions for the current costs of building and operating wind projects were based on information from recent projects installed in the Midwest. We assumed a gradual decline in capital and operation and maintenance (O&M) costs and a steady increase in efficiency and production of wind projects over a 20-year period based on trends from a 1997 study by the Electric Power Research Institute (EPRI) and the US Department of Energy (DOE).[27] The study predicts a decline in capital costs largely due to increasing production volumes over time and a decline in O&M costs from economies of scale from large turbines and taller towers. We assumed a typical project size of 50 MW to achieve greater economies of scale in construction and volume purchases of wind turbines from manufacturers. While smaller projects or clusters of small projects could be developed in Nebraska, they are likely to be more expensive. For example, the 1.5 MW Springview project had a fairly high capital cost of $1,377/kW. The EPRI/DOE study estimates that a 10 MW project would cost about 20 percent more than a 50 MW project and a 100 MW project would cost about 5 percent less.

Capacity Factor. Capacity factor is the ratio between the amount of electrical energy produced by a generating unit during a given period of time and the amount of electrical energy that could have been produced at continuous full-power operation during the same period.[28] For the year 2000, we assumed a capacity factor of 37 percent based on the long-term projection for the Springview project, as calculated by Global Energy Concepts for the EPRI/DOE Wind Turbine

[27]Electric Power Research Institute and US Department of Energy, *Renewable Energy Technology Characterizations*, December 1997, online at *www.eren.doe.gov/utilities/techchar.html***.**

[28] Energy Information Administration, *Annual Energy Review 1998*.

Verification Program.[29] They based this projection on data from Nebraska's four-year wind monitoring study and two years of actual operating data. In 2000, the Springview turbines operated at a 38.6 percent capacity factor. Springview was assumed to represent a typical site for wind development in Nebraska. The state's wind monitoring study recorded higher wind speeds at two of the six sites with wind resources suitable for commercial development. We assumed, based on projections from the EPRI/DOE study, that capacity factors would increase over time due to taller towers, larger rotors, increased efficiency, and a reduction in losses due to weather, blade soiling, control and turbulence, line losses, and other factors.

Federal Incentives. Two federal incentives are available to encourage wind power development. A Production Tax Credit (PTC), currently worth 1.7 cents per kWh for the first 10 years of a project's operating life and adjusted annually for inflation, is available to private wind developers. The Renewable Energy Production Incentive (REPI) is an equivalent payment that public utilities can apply for on an annual basis for the first 10 years of a project's life. Funding for the REPI is subject to annual appropriations by Congress, which makes its long-term availability more uncertain. Since funding for the PTC basically comes from a reduction in taxes that are paid to the US Treasury, its availability is virtually guaranteed once a project is built. While these incentives are scheduled to expire at the end of 2001, there appears to be broad bipartisan support from key members of Congress and the Bush administration to extend the incentives for at least five years. Thus, for this analysis, we assumed that the PTC and REPI would be extended for five years.

The amounts shown in Table 1 represent the value of the incentives spread out over a 20-year period to make this value comparable with the annualized value of other costs. The value of the PTC is higher than the REPI payment because private developers can receive additional tax benefits from the tax credit. The PTC is actually worth about 2.4 cents per kWh for the first 10 years to private developers with sufficient tax liability.[30]

Transmission Costs. Transmission capacity in Nebraska and the Midwest is limited, particularly in rural areas where the best wind resources often exist. While existing and proposed wind projects in Iowa and Minnesota have required relatively modest new investments in transmission, any significant new development in those areas is likely to require new or upgraded transmission lines to get the wind power to demand centers. The situation is likely to be similar in Nebraska. For this analysis, we assumed that 150 MW of wind power could be added in Nebraska without incurring additional transmission costs beyond interconnection to the existing transmission system. These costs are included in the capital cost estimates above. For wind power capacity additions above the first 150 MW, we assumed that new transmission lines, substations, and collection systems would cost \$120 per kW.[31]

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[29] H. Rhodes, J. VandenBoshe, T. McCoy, and A. Compton, Global Energy Concepts, and Brian Smith, National Renewable Energy Lab, *Comparison of Projections to Actual Performance in the DOE-EPRI Wind Turbine Verification Program*, Presented at the Windpower 2000 Conference in Palm Springs, Calif., May 2000.

[30] For more information on this topic see Wiser and Kahn, *Alternative Windpower Ownership Structures: Financing Terms and Project Costs*, May 1996, p. 36.

[31] This cost estimate was based on a very simple analysis completed for this report by Thomas A. Wind, PE, Wind Utility Consulting, Jefferson, Iowa. The estimate includes the cost of installing 180 miles of 345 kV transmission

Ownership and Financing. Our analysis considered three possible ownership scenarios:

- 100 percent public
- 100 percent private
- 50 percent public/50 percent private

Table 1 shows the estimated cost of developing wind power in Nebraska for both public and private ownership. For publicly owned facilities, we assumed 100 percent tax-exempt bond financing at a 6.5 percent interest rate, with cost recovery over a 20-year period.[32] For privately owned facilities, we applied the same financing assumptions as in the EPRI/DOE study for a generating company using balance sheet or corporate finance, where debt and equity investors hold claim to a diversified pool of corporate assets.[33] Florida Power and Light, the largest wind developer in the United States, uses this form of financing.

Financing costs have a significant impact on the cost of wind power, as Table 1 shows. This is because wind power is a capital-intensive technology, with low operating costs. Based on our financing assumptions, publicly financed facilities are between 53 and 65 percent less expensive than privately financed projects. The higher value the PTC provides for private facilities helps offset some of the cost advantage of publicly financed projects. The level of funding available for the REPI incentive, on the other hand, is less certain, as discussed above. Without the REPI payment, we estimated that publicly financed projects would be as much as 15 percent less expensive than privately financed projects with the PTC.[34]

Property Taxes. The extent to which wind development in Nebraska would generate property tax revenues will depend on who owns the project. In Nebraska, all electricity is from publicly owned entities. Public power in the state is subject to a unique taxing structure. Public power districts pay 5 percent of annual gross revenue derived from retail electricity sales that includes an amount equal to the 1957 payment in lieu of taxes. Under this structure, wind projects would not be subject to property tax payments. However, wind projects owned by municipal utilities would contribute to the tax local base. Private wind development in rural areas would pay property taxes at an average statewide rate of about 1.5 percent of the project's assessed value.[35] Property taxes are included in O&M costs.

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line and associated substation equipment in North Central Nebraska to connect approximately 650 MW of wind power to the existing electric grid.

[32] This is the same interest rate used for financing wind projects in the Nebraska Power Association's *1997–2016 Integrated Resource Plan*, 1996.

[33] EPRI/DOE, 1997, p. 7-1. A typical generating company capital structure consists of 35 percent debt at a 7.5 percent annual return and 65 percent equity at a 13 percent return. We have assumed that all costs are recovered over a 20-year period.

[34] Ryan Wiser and Edward Kahn, 1996. *Alternative Windpower Ownership Structures: Financing Terms and Project Costs*, Lawrence Berkeley National Laboratory, Berkeley, Calif.

[35] Kate Allen, legislative aide to Senator Don Preister, personal communication, January 2001.

Total Cost of Wind Power. Our estimate of 3.8 cents per kWh in 2000 for the total cost of privately owned wind projects (over a 20-year period) is within the range of costs of existing projects in the Midwest. For example, the large projects near Alta, Iowa, and Lake Benton, Minnesota, are reportedly producing power for 3 to 5 cents per kWh. Florida Power and Light recently proposed a 100 MW wind project for Hancock County, Iowa, that is expected to generate electricity at 2.8 cents per kWh over a 20-year period. [36] All reported costs include the production tax credit.

Table 1. Wind Technology Cost and Performance Projections for a 50 MW Wind Farm

	2000	2005	2010	2015	2020
Hub Height (m)	65	70	80	85	90
Rotor Diameter (m)	50	55	55	55	55
Capital cost ($/kW)	1,100	939	810	726	660
O&M Cost (¢/kWh)	0.8	0.65	0.5	0.45	0.4
Capacity factor (%)	37.0	38.6	42.1	43.1	43.2
Total Cost without Incentives & Transmission					
Public Ownership (¢/kWh)	3.3	2.7	2.1	1.9	1.7
Private Ownership (¢/kWh)	5.2	4.2	3.3	2.9	2.6
REPI (¢/kWh)	(1.0)	(1.0)	0	0	0
PTC (¢/kWh)	(1.4)	(1.4)	0	0	0
Transmission ($/kW)	0	120	120	120	120
Total Cost with Incentives & Transmission					
Public Ownership (¢/kWh)	2.3	1.9	2.3	2.1	1.9
Private Ownership (¢/kWh)	3.8	3.3	3.7	3.3	3.1

Notes:
All costs and incentives are levelized over a 20-year period.
Hub Height refers to the distance from the ground to the center of the rotor.
REPI applies to public ownership, PTC applies to private ownership.

The Avoided Costs of Wind Power

The avoided costs or "market value" of wind projects built in Nebraska will depend on the type, location, cost, and performance of the displaced capacity and generation. Our assumptions for these variables are explained below and summarized in Table 2.

Displaced Capacity. The Mid-Continent Area Power Pool (MAPP), which includes Nebraska and all or part of five other states in the upper Midwest, allows utilities with intermittent generation like wind power, to claim a certain percentage of the projects nameplate capacity as firm capacity. The MAPP method for determining the capacity credit is based on the correlation between wind power output for specific sites and utility load data. The credit varies by month

[36] Presentation by Florida Power & Light to the Governor's Energy Policy Task Force, Des Moines, Iowa, January 3, 2001.

and the four-hour window when the utility normally peaks, and is based on the median value of wind generation (with half of the hours being both above and below this value).

Several wind energy experts believe that the MAPP approach underestimates the actual capacity value of wind because it only looks at select hours during the months. The more appropriate way to determine the capacity value of wind is to look at the statistical correlation between wind output and hourly utility load data throughout the year and over a long period of time. The reason is that wind can often displace conventional capacity during other times of the year besides the summer months when most utilities reach their peak demand, and particularly during the winter, when many utilities in the upper Midwest experience periods of high electricity demand.

A 1994 study by the Nebraska Power Association calculated capacity credits for wind power across a wide range of conditions using wind patterns from Ainsworth.[37] The study found that for wind speeds similar to the Springview project, the capacity credit was slightly higher than the capacity factor of the project. Several other studies that have correlated measured hourly wind speeds to utility loads for specific locations have found capacity credit values that are similar to a project's capacity factor.[38] Therefore, in this analysis, we assumed that the capacity credit equals the capacity factor of the Springview project.

As discussed in the introduction, Nebraska is likely to need new electric generating capacity at some point between 2005 and 2010, according to the most recent integrated resource plan developed for the state. The capacity deficit in Nebraska is projected to reach 1,600 MW or 25 percent of the state's electricity needs by 2014. In addition, the upper Midwest is projected to face a deficit of around 5,000 MW by 2006. A large portion of the state and regional deficit is likely to be met with new natural gas combustion turbines (NGCT) and natural gas combined cycle (NGCC) power plants, which have been the technologies of choice for new generation elsewhere. In this study, we assumed that half of the capacity displaced by new wind projects would be NGCC plants and the other half would be NGCT plants.[39] This assumption was based on regional data from a UCS analysis that examined the impacts of a federal renewable portfolio standard.[40]

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[37] Nebraska Power Association, *Statewide Wind Resource Preliminary Economic Study*, April 1994. Capacity credit estimates can be found in Chapter 6.

[38] See Michael Milligan and Brian Parsons, *A Comparison and Case Study of Capacity Credit Algorithms for Intermittent Generators*, National Renewable Energy Laboratory, NREL/CP-4440-22591, March 1997, available online at *www.nrel.gov/wind;* and Theresa Flaim and Susan Hock, "Wind Energy Systems for Electric Utilities: A Synthesis of Value Studies," National Renewable Energy Laboratory, Golden, Colorado, 1984; and UCS also completed an analysis in *Powering the Midwest* of the correlation between measured hourly wind speeds in Holland, Minnesota, and hourly load data from Northern States Power based on data from 1985 through 1991. We found that during the top 50 load hours of 1988—a very hot year—there was a 58 percent probability that wind farm output would exceed 50 percent of rated capacity and a 70 percent chance that wind output would exceed 25 percent of rated capacity. We calculated that average annual wind power output of a wind plant at the Holland site would be 37 percent of rated capacity. The average output or capacity factor was close to what we estimated to be the capacity value of a wind power plant at the Holland site.

[39] This capacity mix is based on estimates of summer capacity credit

[40] Steve Clemmer, Alan Nogee and Michael Brower, *A Powerful Opportunity: Making Renewable Electricity the Standard*, 1999.

Displaced Generation. When new wind projects in Nebraska generate power, they will displace generation from the most expensive power plant operating at that point in time. In most cases, this would be generation from new NGCC plants. However, there will be times during the year wind projects will be generating power and the demand for electricity is low. During these times, wind is likely to displace existing coal generation. In this analysis, we assume that two-thirds of the generation displaced by wind power would come from NGCC plants and one-third would come from coal plants. This assumption was based on regional data from an analysis we completed that examined the impacts of a federal renewable portfolio standard.

Table 2. Avoided Costs of Wind Power

	2000	2005	2010	2015	2020
Capital Costs ($/kW)					
NGCT	462	435	375	356	353
NGCC	576	551	499	478	466
Transmission	35	35	35	35	35
Fixed O&M Costs ($/kW-yr)					
NGCT	8.9	8.9	8.9	8.9	8.9
NGCC	14.1	14.1	14.1	14.1	14.1
Wind Capacity Credit					
Wind Capacity Credit (%)	37.0%	38.6%	42.1%	43.1%	43.2%
Wind Capacity Factor (%)	37.0%	38.6%	42.1%	43.1%	43.2%
Displaced Capital Cost ($/kW)	554	528	472	452	445
Displaced Fixed O&M ($/kW-yr)	11.5	11.5	11.5	11.5	11.5
Fixed Charge Rate	10.1%	10.1%	10.1%	10.1%	10.1%
Subtotal (¢/kWh)	0.77	0.76	0.68	0.66	0.65
NGCC Operating Costs					
Variable O&M Cost (¢/kWh)	0.01	0.01	0.01	0.01	0.01
Fuel Cost ($/MMBtu)	3.98	2.87	3.02	3.57	3.98
Levelizing Factor for Fuel Escalation	1.00	1.21	1.25	1.22	1.22
Heat Rate (Btu/kWh)	6,927	6,639	6,350	6,350	6,350
Fuel Cost (¢/kWh)	2.76	2.31	2.39	2.76	3.08
Subtotal (¢/kWh)	2.77	2.32	2.40	2.77	3.09
Coal Operating Costs					
Variable O&M Cost (¢/kWh)	0.60	0.60	0.60	0.60	0.60
Fuel Cost ($/MMBtu)	0.58	0.56	0.54	0.52	0.50
Levelizing Factor for Fuel Escalation	0.94	0.93	0.94	0.94	0.94
Heat Rate (Btu/kWh)	10,700	10,700	10,700	10,700	10,700
Fuel Cost (¢/kWh)	0.58	0.56	0.54	0.52	0.51
Subtotal (¢/kWh)	1.18	1.16	1.14	1.12	1.11
Total (¢/kWh)	**3.0**	**2.7**	**2.7**	**2.9**	**3.1**

Cost and Performance of Conventional Power Plants. To calculate the value of the displaced capacity and generation, we used assumptions for the cost and performance of new natural gas power plants from the Energy Information Administration (EIA).[41] Natural gas prices were based on EIA data for the region. We adjusted gas prices upward for the period 2000–2003 to reflect the recent increase in gas prices as reported in EIA's *Short-term Energy Outlook* (December 2000).

Our assumptions for coal generation were based on actual operating data for existing coal plants in Nebraska. Current coal prices were based on the statewide average. We assumed that coal prices would decline over time in real terms (without inflation) based on long-term projections from EIA.

Cost of Producing 10 Percent of Nebraska's Electricity from Wind Power

To estimate the economic impacts of developing wind power in Nebraska, we assumed that the renewable portfolio standard proposed in LB 645 would be implemented.[42] The proposal would require that 1 percent of each retail electricity supplier's total sales to Nebraska customers come from renewable energy sources other than hydroelectric in 2003. The percentage would rise 1 percent in each succeeding year to 10 percent in 2012, then remain at 10 percent each year thereafter.[43] We assumed that retail electricity sales would rise 1.5 percent per year, on average.[44] We also assumed that the requirement would be met entirely with wind power because its cost is relatively low compared with other renewable energy technologies.[45]

Based on these assumptions, we projected that about 80 MW of new wind capacity would be needed, on average, each year over the 10-year period to meet the RPS target, resulting in a total installed capacity of just over 800 MW of wind power in 2012, as Figure 5 shows. After 2012, wind capacity steadily increases to 900 MW, as the 10 percent standard remains in place while total electricity sales continue to grow. Based on the assumptions in Table 2, we projected that this new wind capacity would displace 170 MW of new natural gas combustion turbine plants and 170 MW of natural gas combined cycle plants by 2012. Figure 5 shows the total capacity displaced from new natural gas plants.

As discussed above, two of the most important variables affecting the cost of wind power are ownership (public vs. private) and financing and the availability of the federal PTC (for privately financed projects) and REPI (for publicly financed projects). We considered the following three scenarios to show a range of potential costs for different ownership structures:

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[41] EIA, Assumptions to the Annual Energy Outlook 2001 (AEO 2001), DOE/EIA 0554 (2001), online at *www.eia.doe.gov*.

[42] LB 645 was introduced by Senator Preister in the 97th Legislature of Nebraska, January 16, 2001.

[43] The bill also includes a separate standard for hydro of 7% in 2003 through 2012. Wind and other non-hydro renewables can compete with hydro to meet this standard, but it is unlikely that any non-hydro renewables would be developed given the availability of large amounts of low cost of hydro generation.

[44] Nebraska Public Power Association, *Statewide Integrated Resource Planning Report (1997-2016)*, October 1996. The report projects that peak electricity demand in Nebraska will grow by 1.3% per year and retail electricity sales will grow by a slightly higher, but unspecified amount.

[45] In reality, other renewable energy technologies would likely be installed to meet the requirement, but in relatively small quantities.

- Under a low-cost scenario where all new wind and natural gas projects are publicly owned and the REPI is extended through 2006, we estimated that the RPS would save Nebraska electricity consumers $12.5 million per year, on average, over a 20-year period compared with business as usual. This is equivalent to a savings of about 19 cents per month for a typical non-electric heating household using 500 kWh per month.

- Under a high-cost scenario where all new wind and gas projects are privately owned and the PTC is not extended after 2001, we estimated that the RPS would cost Nebraska electricity consumers about $34 million per year, on average, over a 20-year period compared with business as usual. This would be an extra 59 cents per month for a typical non-electric heating household using 500 kWh per month.

- Under a scenario where half of the wind and gas projects are owned by public entities and the other half are owned by private developers, and the PTC and REPI are extended for 5 years, the cost of the RPS would be $3.5 million per year, on average, over a 20-year period compared with business as usual. This would be an extra 7 cents per month for a typical non-electric heating household using 500 kWh per month. Going forward we used the 50/50 split between public and private ownership as the base case for our analysis.

These results are summarized in Table 3.

Figure 5. Wind Power Capacity under an RPS of 10 Percent by 2012 in Nebraska and Displaced Capacity from New Natural Gas Plants

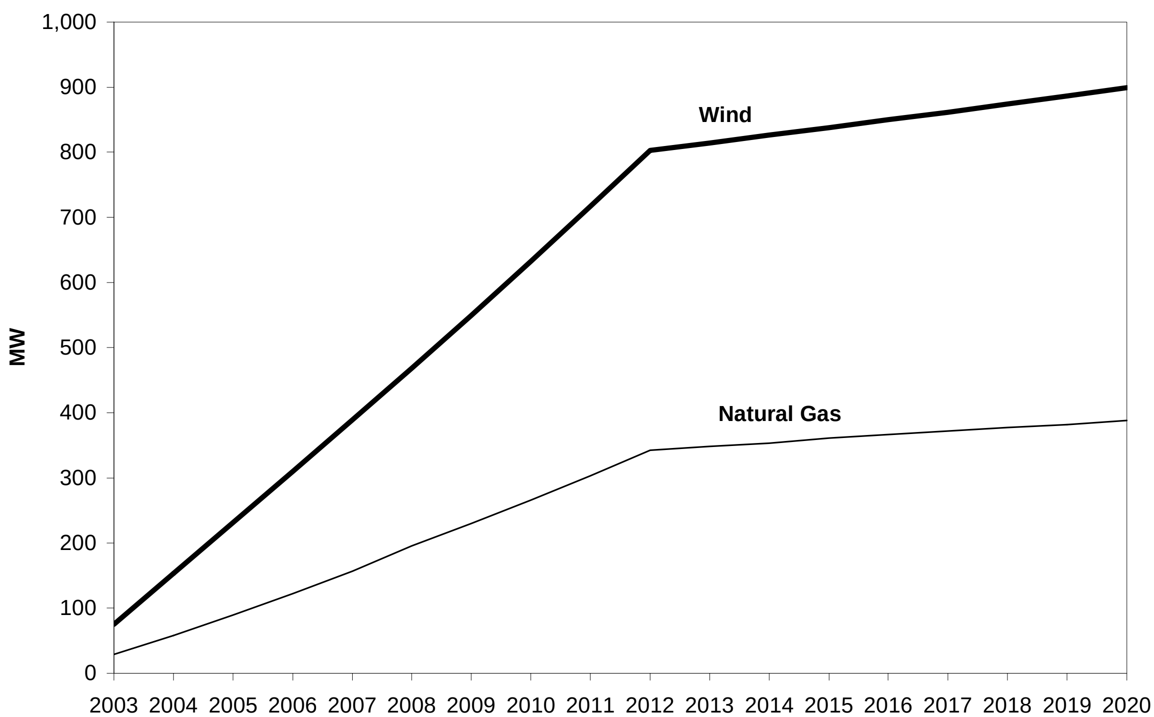

Table 3. The Incremental Cost of Providing 10 Percent of Nebraska's Electricity from Wind Power by 2012 vs. an Equivalent Amount of Electricity from Natural Gas and Coal

	Ownership					
	100% Public		50% Public/Private		100% Private	
Impact	with Incentive[a]	without Incentive[a]	with Incentive[a]	without Incentive[a]	with Incentive[a]	without Incentive[a]
Annual Avg cost over 20 years (mil 2000$)	-12.5	-2.2	3.5	15.9	19.6	34.1
Rate Impact in 2012 (mills/kWh)	-0.38	-0.02	0.15	0.58	0.68	1.18
Avg cost per household in 2012 ($/month)[b]	-0.19	-0.01	0.07	0.29	0.34	0.59
Change in monthly bill in 2012 (%)[c]	-0.4%	0.0%	0.2%	0.7%	0.8%	1.4%
Net Present Value (mil. 2000$)	-102.6	-5.2	20	136.6	142.1	278.4

Notes:
Negative numbers represent incremental savings.
a. For 100 percent public financing scenario, incentive is REPI; for 100 percent private financing scenario, incentive is PTC; for 50 percent public/50 percent private, incentive is split between REPI and PTC.
b. Assumes a typical non-electric heating household using 500 kWh per month.
c. Assumes an average price of 6.4 cents per kilowatt-hour.

Estimating Economic Impacts

To estimate the economic impacts of wind development, we make three important assumptions. First, we assumed that half of all new wind and natural gas facilities are financed by public power entities and half are financed by private developers. Second, we assumed that all wind, natural gas, and coal generation is produced in Nebraska rather than imported from outside the state. Third, we assumed that the REPI and PTC would be extended for five years.

We used an input-output model called IMPLAN to estimate the economic impacts of building and operating wind projects in Nebraska.[46] Input-output models trace supply linkages in the economy, allowing us to analyze the changes in expenditures brought about by investments. Expenditures affect overall economic activity and, depending upon the type of expenditure, support varying levels of employment, income, and economic activity. To capture the full economic multiplier effects of building and operating wind projects in Nebraska, three separate effects—direct, indirect, and induced—must be examined for each change in expenditure.

- The **direct effect** refers to the on-site or immediate effects created by an expenditure. This would include the on-site expenditure and jobs of the electrical or special trade contractors hired to build, operate, and maintain wind projects.

- The **indirect effect** refers to when a contractor or vendor receives payment for goods or services delivered and is then able to pay others who support their own businesses. It includes equipment manufacturers and wholesalers who provide the new technologies. It also

[46] IMPLAN was developed by the Minnesota IMPLAN Group, Inc., Stillwater Minnesota. More information is available online at *www.implan.com.*

includes such people as the banker who finances the contractor, the accountant who keeps the books for the vendor, and the building owner where the contractor maintains local offices.

- The **induced effect** refers to the wages spent on goods and services in the local economy by the people who are directly and indirectly employed by the construction and operation of the wind facilities.

The sum of these three effects yields a total effect that results from a single expenditure. The employment and income ultimately generated by new investments in wind power depends on the structure of the local or state economy. States that produce fabricated metal or electronic products, for instance, could conceivably benefit from expanded sales of locally manufactured wind turbines. Similarly, states that have the necessary skilled trades and experienced construction firms would benefit from local employment during construction of the wind projects. As Table 2 shows, our analysis estimated that the cost of building and operating wind facilities would be roughly the same over time as the assumed mix of new natural gas and existing coal generation.

Potential Economic Impacts of Wind Development in Nebraska

The economic impacts of providing 10 percent of Nebraska's electricity with wind power in 2012 are compared with the impacts of generating an equivalent amount of electricity from the assumed mix of new natural gas and existing coal plants in Table 4. In terms of jobs, the results of the analysis show that in 2012 the added wind power projects generate 2.4 times more jobs from construction and 1.5 times more jobs from O&M than do coal and natural gas plants. In 2012, wind plants generate 2.6 times more earnings during the construction phase, and somewhat less earnings during the ongoing O&M of the facilities. This is because the vast majority of the cost of wind power is embodied in its up-front capital cost. Once wind projects are installed, they require a relatively modest level of ongoing staff and other expenditures. In contrast, a large share of the cost of natural gas and coal power plants goes to pay for ongoing expenditures for imported fuel. New natural gas power plants also have considerably lower capital costs than wind projects.

Table 4. Economic Impacts of Providing 10 Percent of Nebraska's Electricity with Wind Power in 2012 vs. an Equivalent Amount of Electricity from Natural Gas and Coal[a]

	Jobs	Earnings (Million $)	Gross State Product (Million $)
Wind Power			
Construction[b]	410	20	56
Operation & Maintenance[c]	360	16	29
Natural Gas & Coal Generation			
Construction[b]	173	8	19
Operation & Maintenance[d]	240	20	30
Net Impact of Wind Power			
Construction[b]	237	12	37
Operation & Maintenance	120	–4	–2

Notes:
Figures may not add due to rounding.
a. Assumes all wind, natural gas, and coal generation is produced in Nebraska.
b. Includes the economic activity generated from building new transmission lines to support new wind and natural gas plants.
c. Includes the economic activity generated from royalty payments to landowners.
d. Includes the economic activity generated from expenditures for fuel.

Construction and Manufacturing Impacts

Based on the cost estimates presented in Table 1, total construction and equipment costs for 800 MW of wind capacity installed through 2012 would be $700 million. In addition, we estimated a total capital investment in new transmission lines and associated equipment of $78 million through 2012. The economic impacts reported in Table 4 are based on a total expenditure of $77 million for the installation of 87 MW of wind capacity in the year 2012, which includes $10 million in transmission costs.

Approximately 75 percent of the total construction cost (not including investments in new transmission lines) is for the wind turbines, towers, and related components. Most of this is specialized equipment produced by a relatively small number of businesses around the country. We assumed that all of this equipment, except for half of the towers, would be manufactured outside of Nebraska. The remaining 25 percent of construction related costs are mainly for labor, materials and services to support construction crews. We assumed that most of the expenditures for these activities would be in the Nebraska. These include:

- construction of roads, pads and foundations
- electrical substation, transformer and cabling equipment purchases, construction and installation
- project construction and management, including labor and management wages, vehicles, room and board, field office, legal services, and miscellaneous local purchases
- construction and furbishment of the operations and maintenance facility
- engineering and design
- interconnection of the wind turbines to the electricity system[47]

Overall, we assumed that 30 percent of the total construction-related expenditures for building wind facilities would be spent in Nebraska's economy.

By making a long-term commitment to develop wind power, the RPS could help spur development and expansion of businesses that manufacture wind turbines and related components in Nebraska.[48] As mentioned earlier, Daniels Manufacturing in Ainsworth and Valmont Industries in Omaha are examples of Nebraska companies that have already benefited from wind development in the Midwest. Using the IMPLAN model, we found that if half of the

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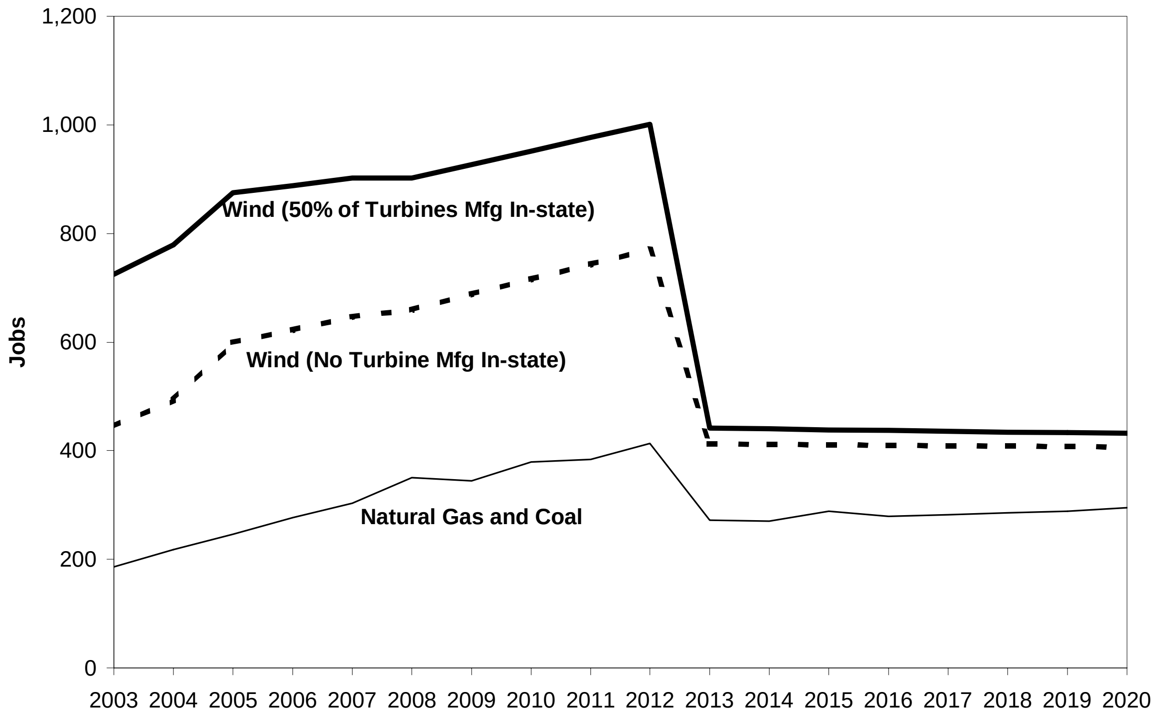
[47] This information is based on the 42 MW Cerro Gordo wind farm in Iowa and the wind farm in Lakota Minnesota, as reported in *Potential Economic Benefits from Commercial Wind Power Facilities in the State of New Mexico*, prepared by BBC Research and Consulting for the New Mexico Energy, Minerals, and Natural Resources Department, July 2000.

[48] One example of manufacturing capabilities expanding to meet local demand is in Sacramento, California. In 1997, the Sacramento Municipal Utility District (SMUD) decided to buy 10 MW of solar photovoltaic systems over the next five years. As part of the winning bid, Energy Photovoltaics, Inc., and Trace Engineering are required to locate their manufacturing facilities in the Sacramento area. These companies are expected to bring as many as 280 new manufacturing jobs to the Sacramento community. See "SMUD Board votes to bring ten megawatts of solar power to Sacramento, Renews commitment to renewable energy," SMUD news release, May 16, 1997. More recently, the City of Chicago agreed to purchase $6 million in photovoltaic panels from the Spire Corporation in exchange for building a manufacturing and assembly plant on a brownfield site in the Chicago.

wind turbines and related components and all of the towers that are needed to meet the 10 percent RPS requirement were manufactured in Nebraska, an additional 250 jobs, $15 million in earnings, and $44 million in gross state product would be supported each year on average over a 10-year period. These potential benefits are illustrated in Figures 6 through 8. Additional jobs and economic activity that could result from exporting equipment to other states are not included in these estimates.

Figure 6. New Jobs from the Construction and Operation of Wind Projects under the RPS vs. an Equivalent Amount of Electricity from Natural Gas and Coal



The wind turbines would offset the need for approximately $171 million in new natural gas power plants. While we assumed that wind power would displace conventional generation and capacity in Nebraska, it is plausible that new wind projects would displace higher cost generation outside the state. Under these circumstances, wind power would generate even greater net benefits for Nebraska than estimated in this analysis.

Operation and Maintenance

Annual expenditures for operating and maintaining wind farms would increase gradually over time to $16.4 million in 2012 as more wind power is added. By 2012, the operation and maintenance of 800 MW of wind farms in Nebraska would create 360 new jobs, $15 million in earnings, and $26 million in GSP. This includes the economic activity generated from landowners spending a share of their royalty payments on local goods and services. By 2012, we estimated that landowners would be receiving $2.2 million in royalty payments, assuming they receive 2.5 percent of the revenues from the project, which is about equal to $2,000 per turbine. We estimated that the projects would also generate property tax revenues worth $5.2 million by

2012. The analysis assumed that half of the wind projects would be financed by public entities and would not be subject to property taxes.

Total expenditures for producing an equivalent amount of generation from gas and coal plants will steadily increase over time to $55 million in 2012, which is over three times higher than the O&M expenditures for wind. Over 80 percent of this total will go to pay for imported fuel, including $38 million for imported gas and $5 million for imported coal in 2012. We assume a portion of the expenditures for fuel are spent in Nebraska to pay for transportation-related costs (i.e., transporting coal by train and gas by pipeline).

Relative Impacts. In 1997, Nebraska employed about 1.2 million people and total personal income was $39.1 billion. While the impacts of developing wind power are relatively small compared with the overall state economy, the jobs and income that would be generated from building and operating wind projects could be significant for rural communities. As shown earlier, Nebraska's 10 windiest counties have higher poverty rates and lower median incomes than the state average, as well as declining populations. New economic activity from wind development could help counteract these trends while diversifying these local economies.

The analysis shows that even without the local benefits of manufacturing, wind power would produce more in-state economic benefits than imported natural gas and coal. If Nebraska is able to attract the manufacturing capacity to build wind turbines or components in state or if wind power displaces out-of-state generation, the economic benefits would be even greater.

Figure 7. Additional Earnings from the Construction and Operation of Wind Projects under the RPS vs. an Equivalent Amount of Electricity from Natural Gas and Coal

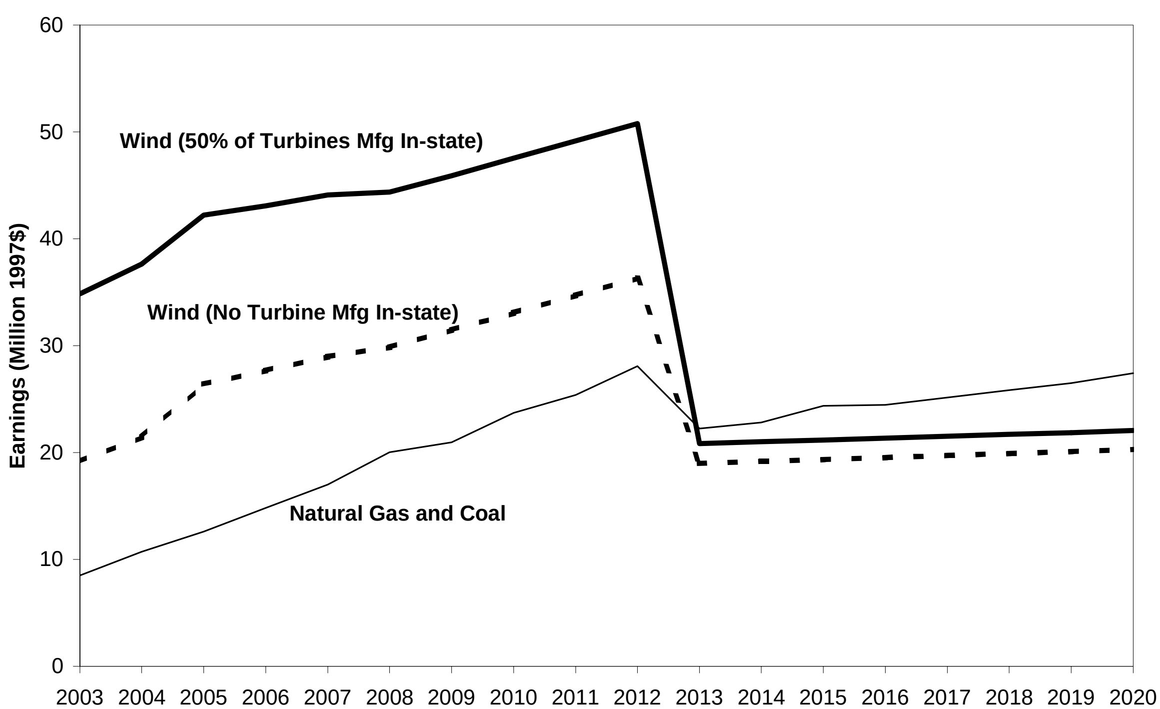
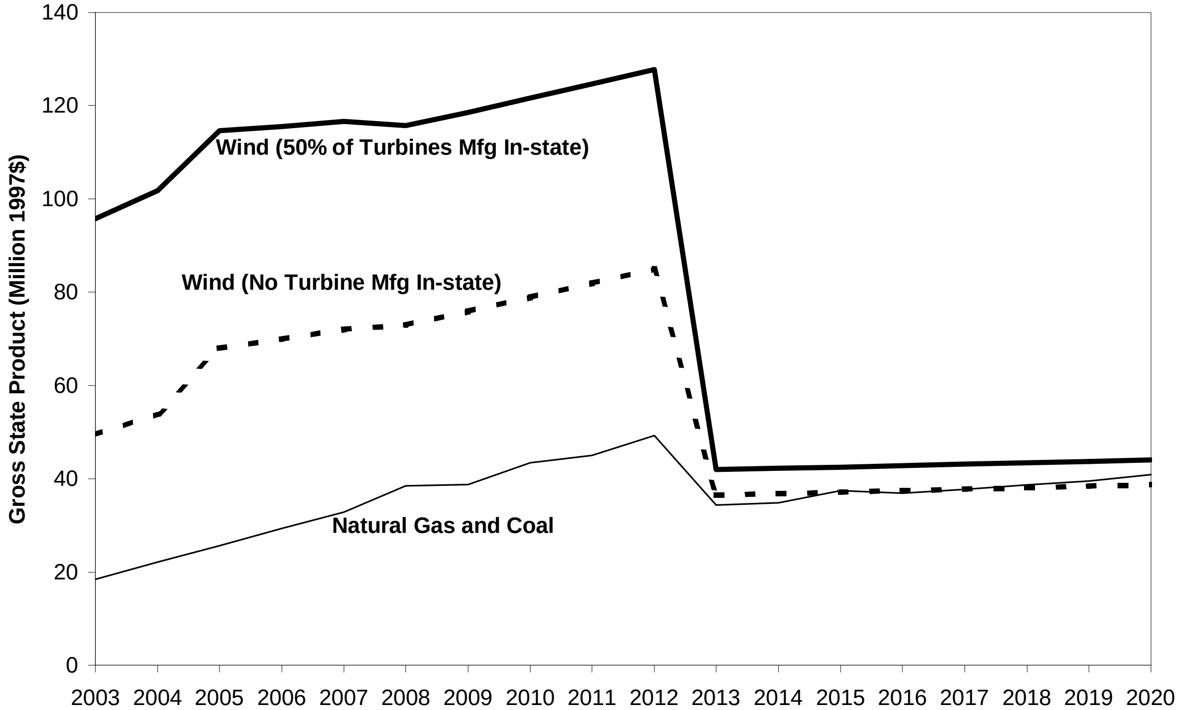


Figure 8. Additional Gross State Product from the Construction and Operation of Wind Projects under the RPS vs. an Equivalent Amount of Electricity from Natural Gas and Coal



Uncertainties

Any analysis that makes projections out into the future inevitably has areas of uncertainty. To the extent possible, we relied on the best and most current information available from actual projects, peer-reviewed studies and credible sources like the Electric Power Research Institute and the Energy Information Administration to develop our assumptions. In areas with greater uncertainty, we made an effort to adopt conservative assumptions.

Nevertheless, potential changes to key variables could increase or decrease projected costs and economic impacts. For example, we assumed that a typical size project would be 50 MW. Recent projects installed in states like Minnesota, Iowa and Texas that have minimum renewable energy requirements like the one modeled for Nebraska have typically been larger than this. As discussed earlier, larger projects are likely to have lower per unit costs. We decided to use higher capital costs for wind than projected in the EPRI/DOE study based on our review of the information available from projects recently installed in the Midwest. However, if smaller projects were installed in Nebraska it would likely increase costs.

As we shown in the report, project ownership can have a significant impact on the cost of wind power. Under the proposed RPS, it is not clear whether projects would be developed by public or private entities. While it appears that Nebraska's public utilities could develop projects at lower cost than private developers, they do not have much experience building and operating wind projects and may not want to take on the risk.

The capacity credit we adopted for wind is basely largely on detailed studies (including one in Nebraska) of the correlation between projected output from a wind project and utility loads. These studies have shown values similar to the assumed capacity factor of a given project. While this may be a reasonable assumption for determining how much conventional capacity wind will actually displace on the system, the value assigned to a given project will be based on the method MAPP uses. It appears that existing projects that have been accredited by MAPP have received lower capacity credits than we assume, though the data is limited. More research is needed to see what an appropriate value would be for a typical site in Nebraska.

It is likely that other resources besides wind would be installed to meet the proposed RPS. We assumed that the proposed RPS would be met entirely with wind power based on the experience of places like Texas that have a similar requirement in place and given the relative economics of wind compared to other renewables. State policies to incentivize other renewables like biomass and solar would likely increase the costs of meeting the RPS, but add fuel diversity and broaden the economic development benefits.

Other variables that we did not consider that could potentially reduce the costs projected in this study include higher natural gas prices and policies to reduce carbon and other emissions.

Conclusion

While the economic benefits of developing wind power are relatively small compared with the overall state economy, the jobs and income that would be generated from building and operating wind power in Nebraska could be significant for farmers and rural communities. Nebraska's windy counties need new economic opportunities. They have higher poverty rates and lower incomes than the state average, as well as declining populations. New economic activity from wind development could help counteract these trends while diversifying these local economies.

This report shows that even without the local benefits of manufacturing wind turbines and related components, wind power would produce more in-state economic benefits than imported natural gas and coal. If Nebraska is able to attract manufacturing capacity or if wind power displaces out-of-state generation, the economic benefits would be even greater. By developing its own wind industry, Nebraska could also become a supplier to the booming US and international wind market.

Nebraska has a powerful opportunity to become a national leader in wind energy development just as it has with ethanol production. States like Iowa, Minnesota, and Texas are demonstrating that progressive state policies are key to fostering the growth of wind power. This report shows that Nebraska can make a significant commitment to develop wind power and maintain its low electricity rates, while providing net benefits to the state's economy and environment. Implementing a renewable portfolio standard in Nebraska could help spur development of new industries, offer a new cash crop to farmers, and provide an important source of jobs and income to rural communities.

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NEWS

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FOR IMMEDIATE RELEASE
August 22, 2006

Gov. Blagojevich unveils ambitious energy independence plan to reduce Illinois' reliance on foreign oil
Governor's plan would meet 50 percent of state's motor fuel needs with alternative homegrown sources made from crops and coal by 2017

Illinois would be the first state to achieve this level of energy independence; Governor sets goal of replacing 50% of our energy supply with homegrown fuels

Plan to triple ethanol production and invest in clean coal technology will create 30,000 new downstate jobs and save consumers billions of dollars

SPRINGFIELD – Governor Rod R. Blagojevich today unveiled a comprehensive long-term energy plan to replace Illinois' dependence on foreign oil with homegrown alternatives. The plan will help free consumers from the grip of foreign oil and gas interests by giving drivers and homeowners alternatives to the high cost of gasoline, stabilize energy prices, give Illinois farmers new markets for their crops, and create 30,000 new jobs. The Governor's plan sets a goal of replacing 50% of the state's energy supply with homegrown fuels by 2017. Illinois would be the first state to reach this level of energy independence.

The Governor's plan would provide new incentives to help triple Illinois' production of ethanol and other biofuels, and build up to ten new coal gasification plants to convert Illinois coal into natural gas, diesel fuel and electricity. The plan also includes construction of a pipeline from Central to Southeastern Illinois to transport carbon dioxide produced by new energy plants to where it can be pumped underground to extract more oil and gas that sits underground in Illinois. Trapping carbon dioxide underground will permanently prevent this greenhouse gas from being emitted into the atmosphere. The plan calls for a dramatic expansion of renewable energy production as well as significant reductions in energy use through investments in energy efficiency and conservation. Specifically, the Governor's plan will:

• Invest in renewable biofuels by providing financial incentives to build up to 20 new ethanol plants and five new biodiesel plants. These increases in ethanol and biofuels production would allow Illinois to replace 50% of its current supply of imported oil with renewable homegrown biofuels;

• Increase the number of gas stations that sell biofuels, so that all gas stations offer 85% ethanol fuel (E-85) by 2017 and help the auto industry to produce more and better flexible fuels vehicles that can run on either E-85 or regular gasoline;

• Invest $775 million to help build up to ten new coal gasification plants that use Illinois coal to meet 25 percent of Illinois' diesel fuel needs, 25 percent of natural gas needs and 10 percent of electricity needs by 2017;

• Build a pipeline to move carbon dioxide, a greenhouse gas, captured from coal gasification plants to oilfields in Southeastern Illinois to extract more oil and natural gas and permanently store the carbon dioxide underground;

• Meet 10% of the state's electricity needs from renewable energy sources by 2015, greatly boost investment in energy efficiency, while finding ways to cut emissions and reduce motor fuel consumption by 10% in 2017.

"No other state has the combination of natural resources that we have here in Illinois. We're the nation's leading producer of soybeans. We're the #2 producer of corn. And we have the nation's third largest reserves of coal. That means opportunity – opportunity to turn more corn into ethanol and more soybeans into diesel fuel. And it means turning coal into home heating fuel and electricity. It means creating 30,000 new jobs downstate. It means helping consumers save billions of dollars in energy costs. And it means finding ways to help drivers use less gas and help homeowners cut their utility bills. Our plan will allow us to meet 50% of our fuel needs with alternative, homegrown sources of fuel by 2017," said Gov. Blagojevich.

"Stop and think about what that means. It means that if we make the right investments now, within ten years, we'll be able to produce enough energy from our own natural resource to cut our dependence on foreign energy in half. That means billions of our hard-earned dollars will stay here at home, in our economy, rather than leaving Illinois forever. We have the resources. We have the technology. We have the expertise. And if we start today, we can solve this problem in the next ten years. No other state can say that. And the federal government hasn't even conceived of that yet. But we can do it here in Illinois," the Governor said.

Part One: Invest in Biofuels

The goal of the Governor's energy plan is to replace 50 percent of the state's current supply of imported oil with renewable homegrown biofuels like ethanol and biodiesel. Since February, the average price of gasoline increased from $2.17 a gallon to more than $3.00. At $3 a gallon, the average person spends about $500 more on gas than last year. The Governor proposes to invest $100 million over the next 5 years to build up to 20 new ethanol plants across Illinois. The additional ethanol production would generate an estimated $1.7 billion in business investment. The Governor proposes investing an additional $100 million over the next ten years to build four plants in downstate Illinois using new technology to create ethanol made from plant waste materials like corn husks and wood pulp – or "cellulosic ethanol." This means boosting the state's annual ethanol production by more than 200 percent and meeting 50 percent of gasoline needs by 2017. And, the Governor's plan would invest $25 million to help build five new biodiesel plants, boosting the state's production by 200 percent to 400 million gallons per year or the equivalent to 25 percent of the state's annual diesel fuel needs by 2017. This additional biodiesel production will generate another $225 million in business investment in Illinois.

Besides building new plants, the Governor will create a task force to drive continued investment in Illinois's biofuels industry. He will also issue an executive order to speed up construction of biofuels plants by expediting state permits and streamlining the permitting process.

These investments in biofuels are expected to create more than 800 direct and permanent jobs at the facilities and 8,000 construction jobs. These jobs will generate an additional 7,000 indirect permanent jobs in total. The plan would greatly help farmers sell to new markets and put farmers on the forefront in the effort to make Illinois energy independent.

Part Two: Increase Use of Biofuels

As Illinois produces more biofuels, the second major goal of the Governor's energy plan is to make sure every gas station in Illinois offers 85% ethanol fuel (E-85) by 2017. To reach this goal, the Governor proposes investing $30 million over the next 5 years to add 900 more E-85 pumps statewide by 2010, meaning 20 percent of Illinois gas stations will offer E-85. Illinois will also work with automakers to offer more flexible fuel vehicles to Illinois drivers, by providing up to $25 million incentives to produce more vehicles that can run on E-85. The state will also increase public awareness about E-85 and promote use by local governments and private fleets. Increasing biofuels production and consumption means cars will use cleaner burning, homegrown fuel and give drivers real alternatives to the high cost of gasoline.

Part Three: Invest in Advanced Coal Gasification Technology

In addition to high prices at gas pumps, consumers are also feeling the heat of high natural gas costs. Natural gas prices have doubled since 2003. Even a five percent annual increase in natural gas translates into $600 more in costs for households by 2015. The Governor's plan would ensure that 25 percent of natural gas consumed in Illinois would come from Illinois coal. Coal is found under 37,000 square miles in Illinois and contains more energy than the oil reserves of Saudi Arabia and Kuwait combined. In fact, Illinois has 38 billion tons of recoverable coal, accounting for 12 percent of all coal in the U.S. The Governor's plan would invest $775 million over the next ten years to help build up to ten new coal gasification plants across Illinois. These plants would meet 25 percent of Illinois' diesel fuel needs, 25 percent of natural gas needs, and ten percent of electricity needs by 2017. Coal gasification technology converts coal from a solid to a gas that can be substituted for natural gas, diesel or electricity. Gasification is the cleanest and most efficient way to convert coal to energy with low emissions of mercury and other air pollutions and allows for the capture and underground storage of carbon dioxide, a greenhouse gas.

Of all states, Illinois is the best suited for large-scale development of coal gasification because of its vast coal reserves and geology appropriate for carbon dioxide storage. Because of these advantages, two Illinois sites were selected out of four national finalists for the FutureGen project, a federal public/private partnership to build the nation's first zero emissions coal fired power plant. The sites are Tuscola and Mattoon. If Illinois wins FutureGen, businesses and the federal government would invest $1 billion in Illinois, creating 150 permanent jobs and 1,300 construction jobs. If Illinois does not win FutureGen, these sites would be ideal to develop coal gasification plants in the future.

An investment of $775 million to build coal gasification plants would generate more than $10 billion in new business investment in Illinois. These plants could create an estimated 1,000 new permanent jobs, 2,500 new mining jobs and 10,000 construction jobs through Central and Southern Illinois. The Governor's plan also calls for partnering with utility companies to purchase electricity and natural gas from coal gasification plants under long term contracts that will help stabilize energy prices for consumers for years to come.

Part Four: Reduce Emissions and Recover More Oil and Gas

Even though coal gasification plants are much cleaner than traditional plants, they still emit carbon dioxide. The fourth part of the Governor's plan will make coal gasification plants even more environmentally friendly by capturing carbon dioxide and safely storing it underground, instead of emitting it into the air. The Governor proposes building a pipeline from gasification facilities in Central and Southern Illinois to Illinois Basin oilfields in Southeastern Illinois. Illinois' oil reserves hold more than one billion recoverable barrels of oil. Because the fields are mature, production cannot increase without using advanced recovery techniques. "Enhanced Oil Recovery," which uses carbon dioxide to extract more oil from existing reserves, could nearly double the amount of petroleum produced by Illinois annually. The 100-mile pipeline would transport the carbon dioxide captured by the coal gasification plants to oilfields and use the pressurized carbon dioxide to extract more oil and gas.

Additionally, the carbon dioxide transported by the pipeline could extract methane from Illinois coal reserves. Illinois coal reserves hold enough methane, a fuel similar to natural gas, to meet all of the state's natural gas needs for seven years.

The pipeline would cost about $100 million to build and would generate an estimated $12 million in annual revenue. The royalties from the recovered oil and gas would subsidize the costs of sequestering the carbon dioxide.

Part Five: Reduce Energy Use, Improve Efficiency, Invest in Renewable Energy

The Governor’s plan also focuses on using more sources of renewable energy and strategies to improve energy efficiency and reduce energy consumption. To make Illinois energy more efficient, the Governor’s plan sets a goal of reducing motor fuel consumption in Illinois by ten percent by 2017, allowing residents to save billions annually in fuel costs. The Governor also proposes to work with the automobile industry, environmental groups, and consumer advocates to form the Illinois Fuel Conservation Task Force to explore strategies to reach the goal of reducing fuel use by ten percent by 2017.

Additionally, the state will focus on ways to boost renewable energy use while finding ways to conserve energy. Illinois has powerful wind resources that can be harnessed to provide electricity to more than one million homes. By adopting a Renewable Portfolio Standard, ten percent of Illinois’ electricity can be generated by clean, renewable energy sources like wind by 2015. The Governor proposes that Illinois adopt an Energy Efficiency Portfolio Standard to greatly increase investments in energy saving programs and technologies that can reduce utility bills for homes and businesses.

In other efforts to improve energy efficiency, the Governor’s plan calls for a $25 million revolving loan fund to support energy efficiency investments in public buildings to reduce government energy usage. The Governor also proposes a $25 million revolving loan fund to support energy efficiency investments by small businesses and manufacturers. Finally, the Governor’s plan includes adopting a building code for single-family homes similar to the code already adopted for commercial buildings to meet modern energy efficiency standards. 42 other states have already adopted such residential efficiency codes.

The Governor’s plan will cost an estimated $27 million annually in general revenue to support $1.2 billion of total capital investment. To pay for the plan, the Governor will increase enforcement efforts to collect taxes from corporations that currently evade taxation. The Illinois Department of Revenue estimates that businesses owe $35-40 million in sales and corporate income taxes to the state. Some businesses collect sales taxes from customers but don’t remit the revenue to the state. Others, mainly out-of-state corporations, illegally shelter income that goes uncollected. The Illinois Department of Revenue will hire 150 more tax auditors to collect these delinquent taxes, producing more than $30 million in Fiscal Year 2007, and as much as $40 million in Fiscal Year 2008. These new revenues will help ensure tax fairness and be collected without raising income or sales taxes or changing Illinois’ tax code.

“Taking these five steps means creating 10,000 permanent jobs and almost 20,000 construction jobs – and almost all of them would be downstate. It means generating over $12 billion in private investment. It means giving our farmers new markets for their corn and soybeans. It means helping Illinois companies produce more ethanol. It means reducing global warming. And most importantly, it means giving consumers a choice and giving consumers a chance. Right now, we’re held hostage to the whims of OPEC. We’re held hostage to complex political situations and unstable leadership in places like Iran and Venezuela. We’re patronized and ignored by our leaders in Washington, and manipulated and extorted by oil barons in the Middle East. It’s about time someone stands up for the American people. It’s about time someone says: here’s the problem, here’s a plan – let’s act and let’s solve this problem,” said Gov. Blagojevich.

“This plan is different from anything we’ve ever done before. It’s different from anything any other state has tried before. But these aren’t normal times. As countries like China and India continue to develop, the demand for oil and gas is only going to grow. The supply will only decline. As a nation, we represent only 4% of the world’s population. But we consume 25% of its annual energy use. Staying the course is not an option. Using our own natural resources is. Someone has to act. And that someone is us.”

Leading the Way to Energy Independence

- Reducing Our Dependence on Foreign Oil and Gas
- Stabilizing Gasoline and Home Heating Prices
- Creating Jobs
- Reducing Energy Use and Protecting the Environment

Governor Rod R. Blagojevich

Introduction

- Our nation is in the midst of an energy crisis: we are dependent on – even addicted to – foreign oil and imported natural gas, which means higher gasoline prices, higher costs to heat our homes, and no control over our own destiny. That has to change.

- Failure at the federal level to find energy solutions has left consumers vulnerable to the whims of OPEC and to natural disasters like Hurricane Katrina.

- Unless Illinois develops a comprehensive plan to address our energy needs, we will remain reliant on foreign fuels and energy prices will continue to rise.

An Energy Crossroads

- Fortunately, here in Illinois we have a choice.
- No other state has the combination of agricultural and geological resources that Illinois has.

- We can use our abundant corn, soybeans and coal to become America's leading producer of alternative fuels.
- We will reduce our dependence on foreign oil, stabilize energy prices, improve energy efficiency, and provide consumers with real alternatives to imported energy sources.

- We will create over 10,000 new, permanent jobs and nearly 20,000 construction jobs.

An Energy Opportunity

- Our 10-year plan will allow us to transform more Illinois corn into ethanol, more soybeans into diesel fuel, and more coal into natural gas to power our vehicles and heat our homes – meeting 50% of our motor fuel needs by 2017.

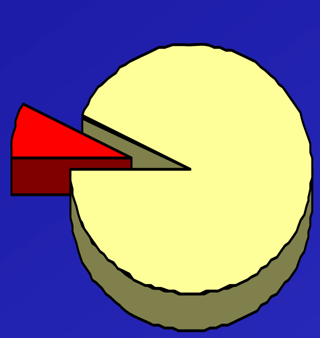
- We will reduce our state's fuel consumption, establishing a goal of cutting fuel use by 10% by 2017, allowing us to save billions annually in fuel costs, and emit less carbon dioxide, a leading cause of global warming.

Our Energy Crisis:
Dependence on Imported Oil & Natural Gas

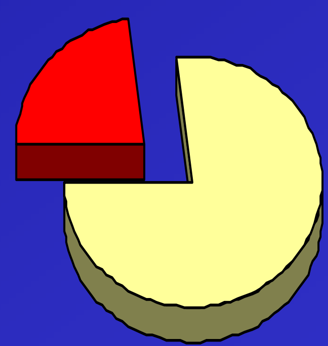
Reliance on Foreign Oil

- Without foreign oil and imported natural gas, Illinois couldn't fuel its cars or heat its homes.
- Illinois only produces:

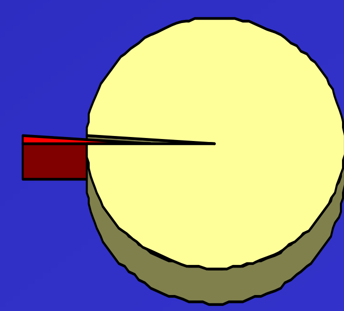
7% of the crude oil we use



23% of the gasoline to fuel our cars



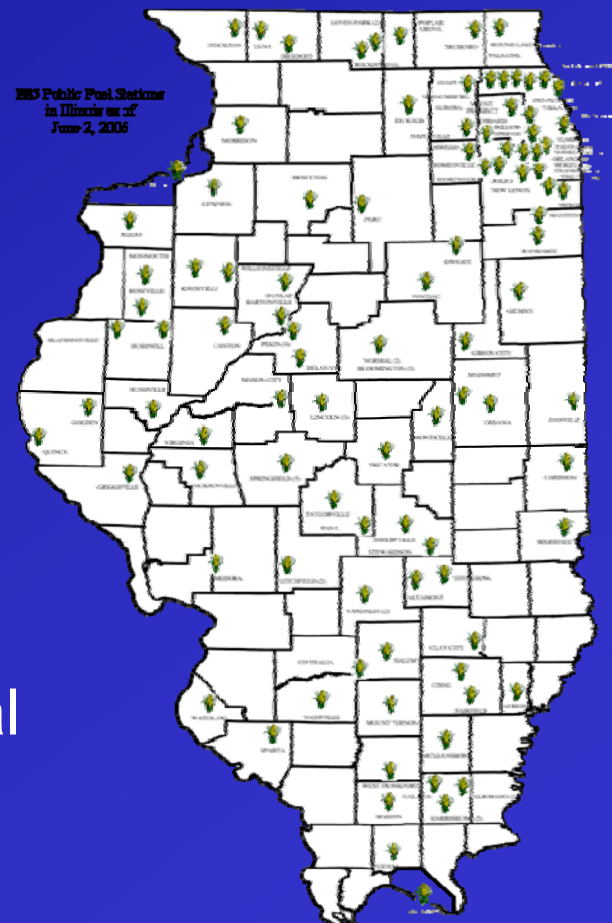
1% of the natural gas to heat our homes



No Alternatives for Consumers

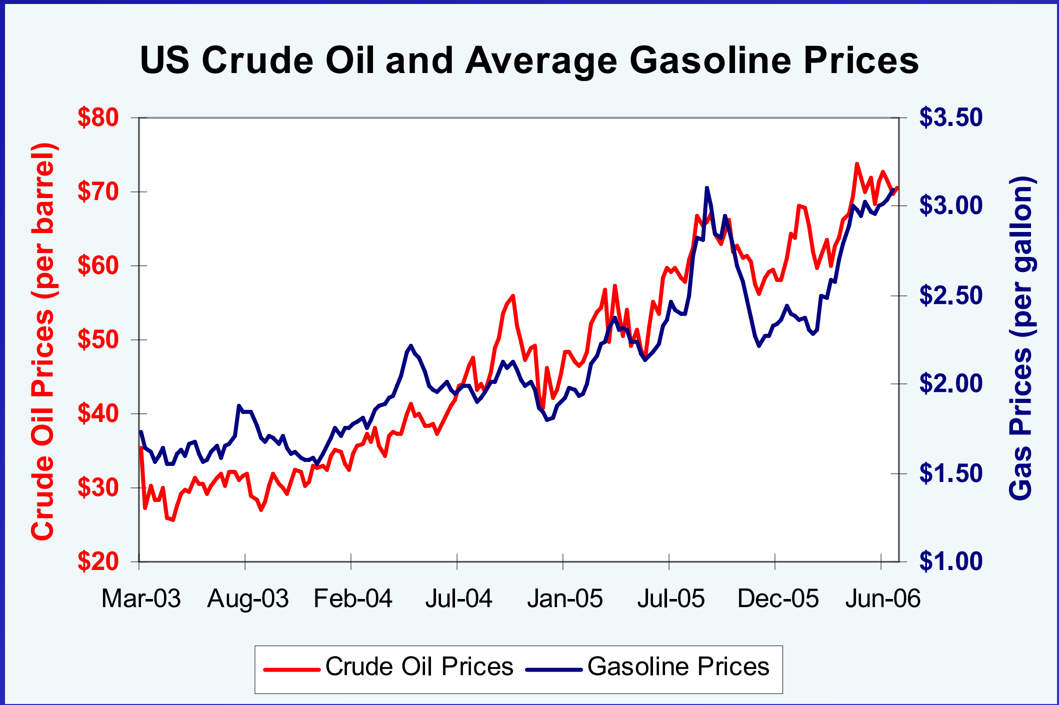
- Today, only 2% of vehicles in Illinois are “flex fuel” vehicles, which can run on either gasoline or ethanol.
- Illinois has about 130 85% ethanol (E-85) pumps – up from just 14 in 2003 – representing just 2% of gas stations in our state.
- The federal government has failed to address our dependence on traditional energy, leaving consumers with few alternatives for powering their cars or heating their homes.

Illinois E-85 Stations



Federal Government Inaction

- The U.S. purchases 19% of its petroleum from the Persian Gulf, including Iran and Iraq. If international tensions continue, so will high oil prices.



- Since the decision to invade Iraq, crude oil prices have more than doubled, leading to skyrocketing gasoline and diesel fuel prices.

- Neither the President nor Congress have taken any concrete steps this year to solve the problem. Instead, they have deliberately stalled bills designed to promote alternative sources of energy.

Handouts to the Oil Industry

- Since the invasion of Iraq, oil companies have enjoyed record profits, including a $36 billion 2005 profit by Exxon Mobil – the largest annual profit ever by a corporation.

- Oil and gas companies still receive billions annually in federal subsidies, including being allowed to pump $65 billion worth of oil from public lands without paying royalties to the government.

- Last year's federal energy bill provided oil companies with over $4 billion in new handouts, but did little to reduce our dependence on foreign oil, help consumers, or boost renewable fuel use.

Don’t Look for Federal Relief

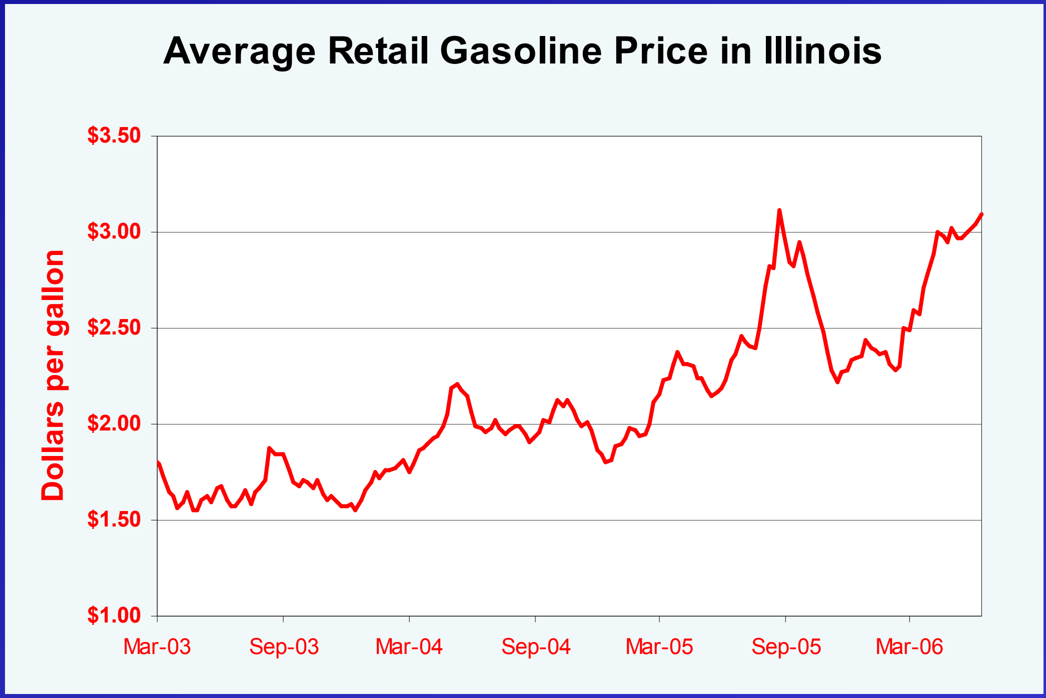
We can’t rely on the federal government to reduce our nation’s dependence on oil. Leaders in Washington have refused to improve automobile fuel economy standards or to aggressively invest in homegrown alternative fuels.

Proposed Federal Solutions	Short-Term Impact	Long-Term Impact	Enacted
1. Rescind tax breaks to oil and gas companies.	Yes	No	**No**
2. Investigate oil company price manipulation.	Yes	No	**No**
3. Institute a windfall excise tax on oil companies.	Yes	Yes	**No**
4. Accelerate research and development of energy options.	No	Yes	**No**

Our Energy Crisis:
Rising Prices

Rising Gasoline Prices

- Since February 2006, the price of a gallon of gasoline in Illinois has risen from $2.17 to more than $3.00.



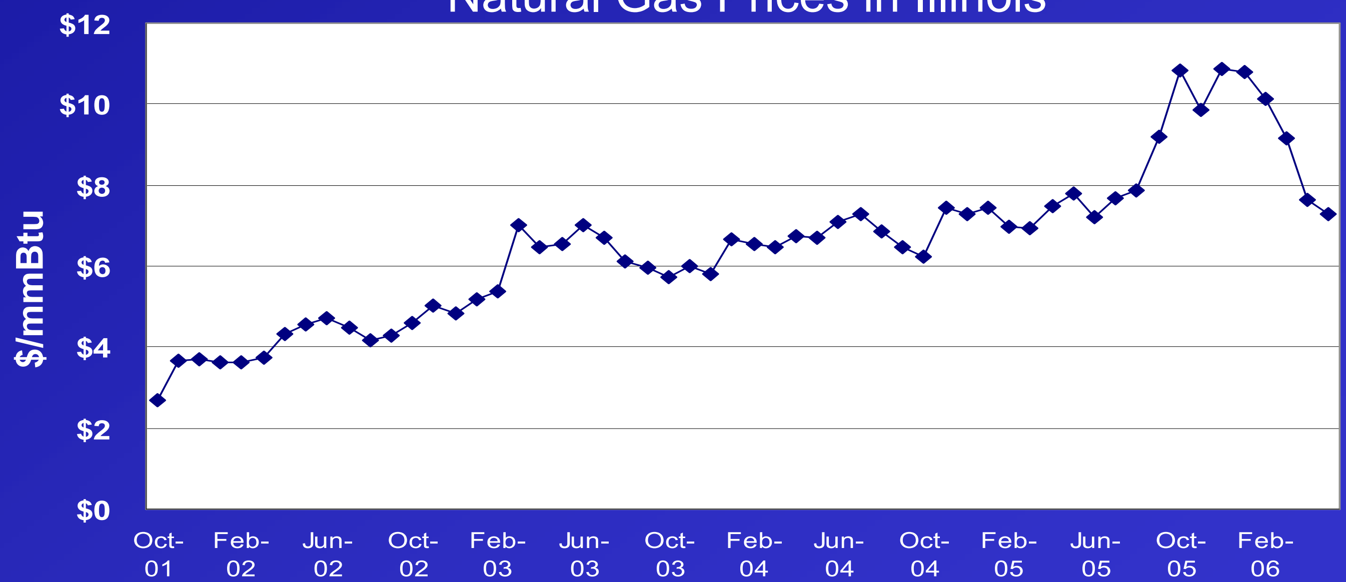
- At $3.00 per gallon, an Illinois resident spends on average about $150 per month on gasoline – or almost $500 annually more than last year.

Rising Natural Gas Prices

- If paying $3 a gallon today isn't bad enough, think about what it costs to heat your home.

- Eight out of ten Illinois residents heat their home with natural gas, and natural gas prices have doubled since 2003, with no end to market volatility in sight.

Natural Gas Prices in Illinois



Falling Natural Gas Supplies

- The U.S. has only 3% of known world natural gas reserves, but accounts for 25% of global consumption.

- Today, about 85% of our supply is produced domestically, but with U.S. natural gas discoveries declining, we will need to find new sources of natural gas.

- Most of the world's natural gas reserves are in countries like Russia and Iran, where political upheaval and instability make these nations an unreliable source of natural gas.

No Relief In Sight

- In 2015, the United States Department of Energy predicts Illinois residents will pay $4.00 per gallon for gasoline, or an average of $600 more per year than they do today, if we don’t act now.

- If we have to import expensive natural gas, even a 5% annual increase in natural gas bills would cost the typical household $600 more annually to heat their home in 2015.

- By acting now, we can begin to solve our energy crisis and help protect consumers if energy prices continue to rise.

A New Energy Path For Illinois

Control Our Energy Destiny

- Illinois – and our nation – is facing a real energy crisis. With federal inaction in the face of rising prices and increasing dependence on foreign fuel, we need a bold energy plan. If the federal government won't act, we will.

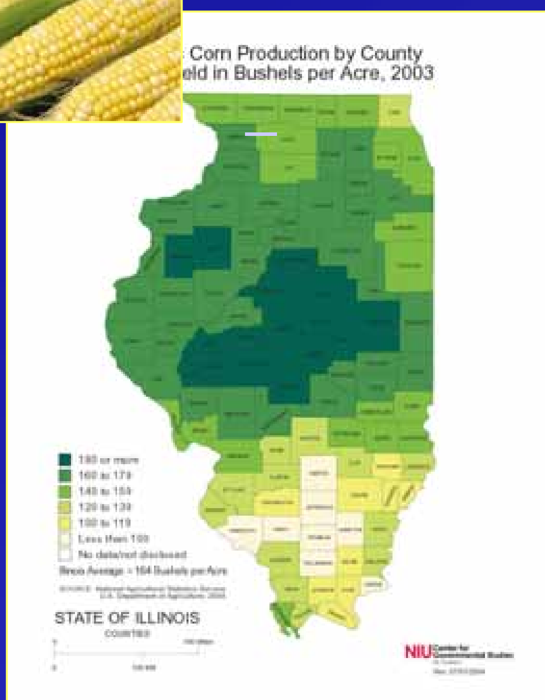
- Illinois has the natural resources to boost fuel supplies, stabilize energy prices and give consumers energy alternatives.

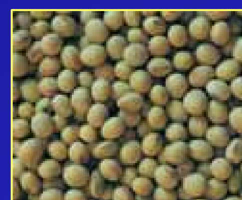
- Illinois can take steps to reduce fuel and energy consumption, which will save consumers money and protect the environment.

Illinois' Abundant Resources

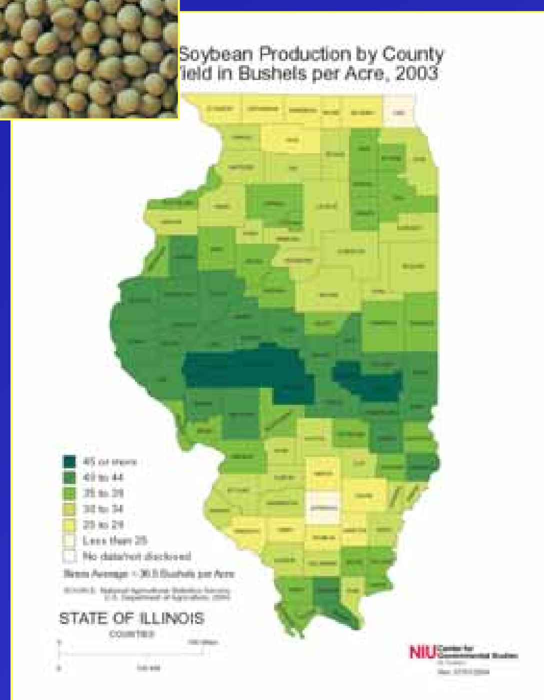
Illinois produces corn, soybeans and coal statewide. These natural resources will help Illinois provide more alternative fuels.

Corn





Soybeans



Coal

Illinois' Abundant Resources

- Illinois is the nation's #1 soybean producer and, with the Governor's elimination of the state sales tax on biodiesel, Illinois is becoming the largest biodiesel market in the country.
- Illinois is the nation's #2 corn producer and, with advances in biotechnology, we expect to dramatically increase the amount of corn we produce over the next ten years.
- Illinois has 38 billion tons of coal – the nation's third largest coal reserve – that can be transformed into clean diesel fuel, home heating gas and electricity.

Our Goals

We can develop Illinois' unique natural resources to:

1. Meet 50% of our motor fuel needs we use by 2017, and 25% of the natural gas we use by 2017.

2. Give consumers real energy choices that can help them use less energy and save money.

3. Create thousands of jobs from new fuel production plants and from increased demand for agricultural crops and coal.

4. Clean our air and reduce greenhouse gas emissions that lead to global warming, by cutting consumption of motor fuel.

Our Plan

We propose a five-part plan to expand Illinois' energy options over the next decade:

1. Invest in renewable biofuels like ethanol made from corn and biodiesel made from soybeans.
2. Increase the number of gas stations that sell biofuels until all gas stations provide E-85, and help the auto industry to make more and better flex fuel vehicles.
3. Invest in natural gas, diesel fuel and electricity produced from Illinois coal using advanced coal gasification technology.
4. Use captured carbon dioxide to boost extraction of resources from of Illinois's oil and natural gas reserves, while reducing the environmental impact of coal gasification facilities.
5. Invest in renewable power and energy efficiency, while reducing emissions and fuel consumption.

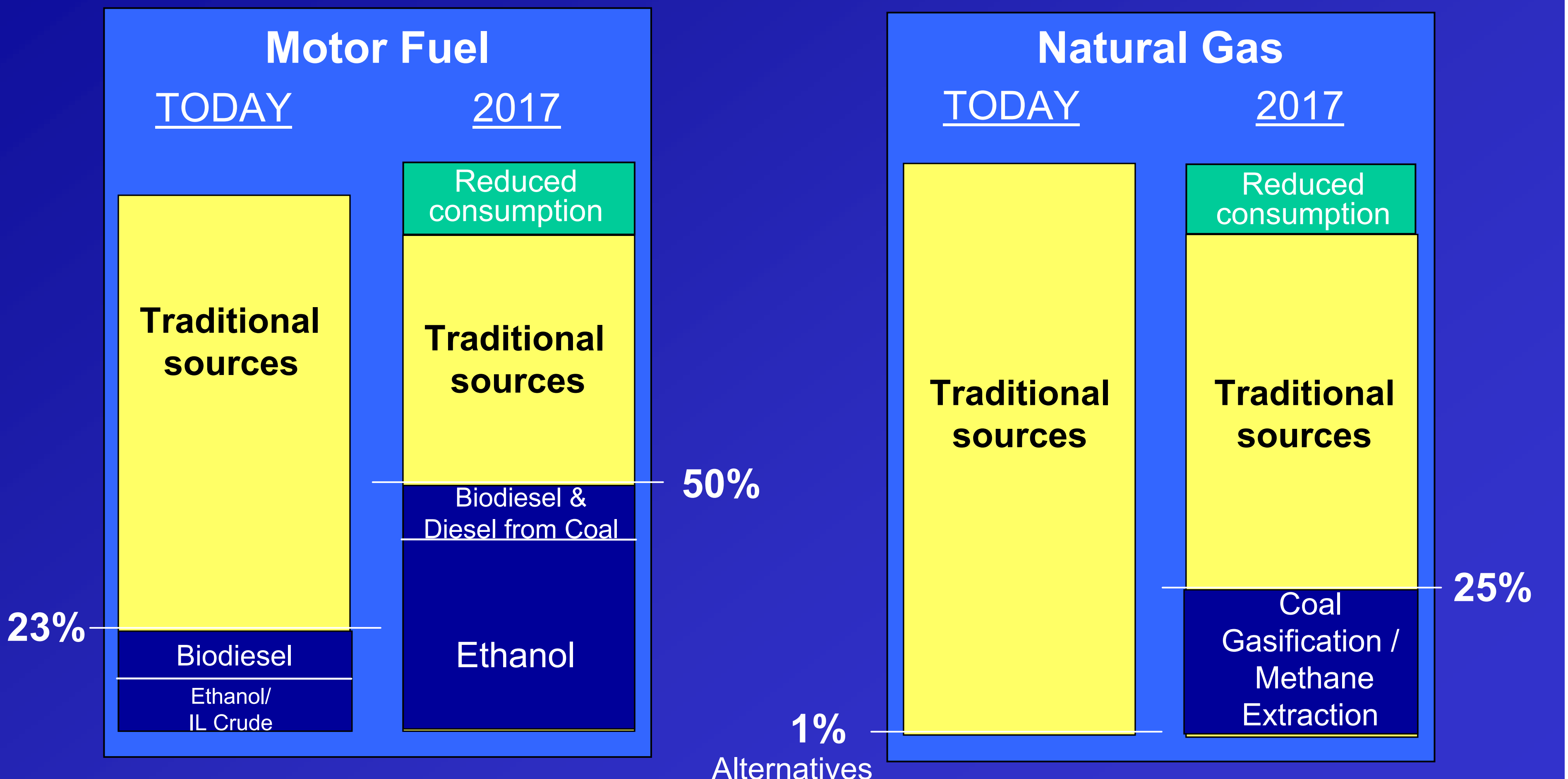
Energy Alternatives

Each element of our plan will play a key role in moving Illinois toward reduced dependence on imported energy.

Elements of Our Plan	Projected Benefits
1. Invest in renewable biofuels like ethanol and biodiesel	50% of our motor fuel needs will be met by Illinois crops by 2017
2. Make biofuels more available and more usable	100% of gas stations will provide E-85 biofuels by 2017 (up from 2% today)
3. Invest in natural gas, diesel fuel and electricity made from Illinois coal	25% of our natural gas will come from Illinois coal by 2017
4. Use recaptured CO_2 to extract more oil and gas	Double Illinois' oil production and boost natural gas production
5. Invest in renewable power / energy efficiency and reduce consumption	Generate cleaner electricity and reduce heating and electricity costs for homes and businesses

Energy Benefits

By 2017, 50% of our motor fuel and 25% of our natural gas in Illinois can come from alternative sources.



Economic Benefits

- Illinois' economy will benefit from this plan through more stable energy prices, more jobs, and billions of dollars in new business investment.
- Economic models indicate that our investment will directly and indirectly generate more than 10,000 new permanent jobs, at least 20,000 construction jobs and over $12 billion in private investment.
- Using more of our natural resources for energy production and reducing our energy consumption will strengthen our economy by keeping more of the dollars we spend on energy here in Illinois.

New Jobs from the Energy Plan

- By implementing this new energy plan we can create over 30,000 jobs: nearly 20,000 construction jobs and 10,900 direct and indirect permanent jobs through 2017.

Initiative	Construction Jobs	Permanent Jobs
Biofuels*	8,000	7,000
Coal Gasification**	10,000	3,500
Renewable Power**	1,700	400
Total	19,700	10,900

* Includes both direct job estimates based on experience with existing and planned biofuels projects plus estimates of indirect jobs using models that predict broader economic impact of biofuels investment.
** Job estimates based on experience with existing and planned gasification and renewable energy projects.

Step 1:
Invest in Biofuels

Ethanol & Biodiesel

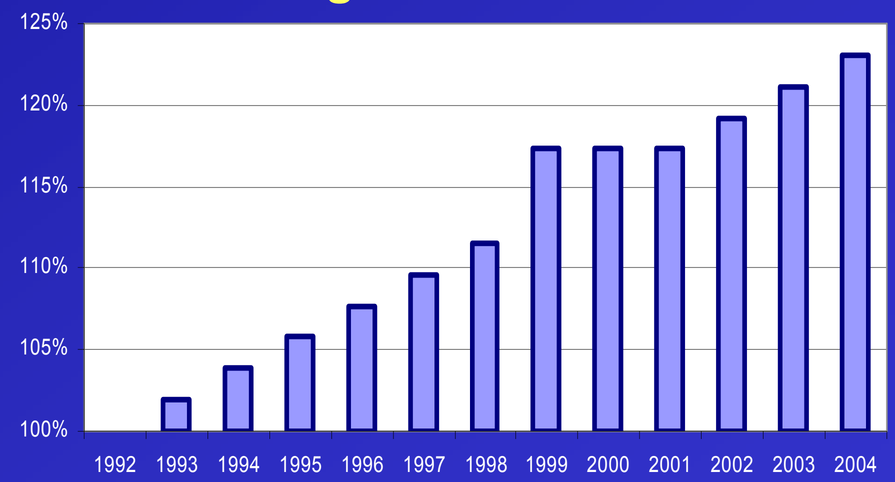
What Are “Biofuels”?

- Biofuels are cleaner burning, homegrown, renewable fuels produced from plants, like ethanol made from corn and biodiesel made from soybeans.
- Unlike fossil fuels, which are exhausted over time, biofuels are a homegrown renewable energy source that is replenished with each year’s new crops.
- Almost all Illinois gasoline already contains 10% ethanol as a fuel additive to help reduce air pollution.
- Auto manufacturers can easily and cheaply produce new vehicles to run on biofuel based E-85.

Biofuels Can Replace Imported Oil

- Growing demand for oil is driving up gasoline prices, from an average in the Midwest of $1.10 per gallon in 1992 to over $3.00 today.

Increasing Demand for Gasoline



- To make matters worse, Americans are using 23% more gasoline than we did in the early 1990's.

- Increasing production of biofuels in Illinois will boost fuel supplies and help stabilize prices.

Invest in New Ethanol Plants

- Over the next four years, we propose investing $100 million to support construction of up to 20 new ethanol plants, using about $5 million in state grants for each plant. We have already attracted several new ethanol plants to Illinois since 2003 with similar grants.
- These new ethanol plants would boost Illinois' annual ethanol production by 200% to 2.5 billion gallons per year, equivalent to 50% of our gasoline needs by 2017.
- With this additional ethanol production, Illinois can generate another $1.7 billion in business investment (investors pay for more than 90% of construction costs).

Invest in New Biodiesel Plants

- Biodiesel is a cleaner burning, homegrown, renewable fuel made from natural oils like soybean oil.
- Biodiesel is used today across Illinois in trucks, buses, farm equipment and other vehicles that run on diesel fuel.
- Over the next four years, we propose investing $25 million to support the construction of up to 5 new biodiesel plants with state grants. We have already attracted new biodiesel plants to Illinois since 2003 using similar grants.
- These new plants would boost Illinois' annual biodiesel production by 200% to 400 million gallons per year, equivalent to 25% of our annual diesel fuel needs by 2017.
- With this additional biodiesel production Illinois will generate another $225 million in business investment, as investors pay 90% of construction costs.

Promote Next Generation Biofuels

- We propose investing another $100 million to support construction of production facilities that can make ethanol from materials like corn husks, wood pulp and switchgrass.

- This new technology would make a fuel called "cellulosic ethanol," and could double the amount of ethanol we produce in Illinois using mainly plant material that would otherwise go to waste. Research on cellulosic ethanol is already under way at the National Corn to Ethanol Research Center at Southern Illinois University in Edwardsville.

- Economic models indicate that constructing 4 cellulosic ethanol plants could stimulate $1.2 billion in private investment.

Support The Biofuels Industry

- Besides building new plants, we propose providing other critical support to Illinois' biofuels industry:
  - We will create the Biofuels Investment and Infrastructure Taskforce to drive continued investment in Illinois' biofuels industry and help make cellulosic ethanol commercially viable.
  - We will issue an executive order to speed construction of biofuels plants by expediting state permits and streamlining the permitting process.
  - We will support further research and development by increasing state support for the National Corn to Ethanol Research Center.
  - We will propose co-firing biofuels by-products with coal in gasification and power facilities to reduce emissions and increase efficiency.
  - We will eliminate the sunset on tax incentives for ethanol and biodiesel.
  - We will upgrade our rail infrastructure to support transportation of biofuels.

Biofuels Create Jobs

- Our investment in Biofuels will create more than 800 direct permanent jobs at these facilities as well as 8,000 construction jobs.
- We estimate that the creation of these jobs will generate new Illinois farming jobs and an additional 6,200 indirect permanent jobs in total.

Part 2:
Increase Use of Biofuels

Increase Access to Biofuels

- As we produce more biofuels, we need to make sure Illinois drivers can find it and use it.
- Auto manufacturers have recently pledged to boost "flex fuel" vehicle production. We will work with Illinois' automakers to make more "flex fuel" vehicles available to consumers.
- More Illinois gas stations must sell E-85 than the 2% that currently do.

Flexible Fuel Dodge Stratus

Provide Biofuels Incentives

- We will invest $30 million to add 900 more E-85 pumps statewide by 2010, so 20% of Illinois gas stations will offer E-85 – and make E-85 available at all Illinois gas stations by 2017.
- We will provide automakers in Illinois with up to $25 million to help them offer more flex fuel vehicles to Illinois drivers, improve the gas mileage of these vehicles, and create the first generation of flex fuel hybrid vehicles.
- We will increase public awareness about E-85 and promote E-85 use by local governments and private fleets.
- We will also require gas stations to notify customers if gasoline prices are expected to rise the next day by 5 cents or more.

Part 3:
Invest in Advanced Coal Technology

Illinois Coal's Great Potential

- Coal is found under 37,000 square miles of Illinois – Illinois' coal reserves contain more energy than the oil reserves of Saudi Arabia and Kuwait.
- Illinois has 38 billion tons of recoverable coal reserves, which is 12% of all the coal in the United States.

What is Coal Gasification?

- Illinois' vast coal reserves can be transformed into transportation and home heating fuels using coal gasification technology.
- Instead of burning coal to release its energy, coal gasification plants convert coal from a solid to a gas that can be processed into a substitute for natural gas, diesel fuel or electricity.
- Gasification is the cleanest and most efficient way to convert coal to energy with low emissions of mercury and other air pollutants, while allowing carbon dioxide to be captured for underground storage.
- Two coal gasification plants are operating now in the U.S. and several coal gasification projects in Illinois are quickly progressing.

FutureGen: The Promise of Coal Gasification

- Among all states, Illinois is best suited for large scale development of coal gasification due to its vast coal reserves and its geology for carbon dioxide storage.
- Because of these advantages, two Illinois sites were chosen among the final four selected as national finalists for the FutureGen project, a federal public/private partnership to build the nation's first zero emissions coal fired power plant. The state's sites are located at Tuscola and Mattoon.
- If we win the FutureGen project, businesses and the federal government will invest $1 billion in Illinois and create 150 permanent jobs and 1,300 construction jobs. If we do not win, we will have several ideal sites to develop gasification plants in the future.

Invest in Coal Gasification

- We will provide the nation's strongest package of financial and tax incentives to develop coal gasification plants.

- We will provide more than $750 million in state incentives to stimulate construction of up to 10 coal gasification plants.

- These plants could meet 25% of Illinois' diesel fuel needs, 25% of our natural gas and 10% of our electricity needs by 2017.

Invest in Coal Gasification

- Investing more than $750 million to help construct up to 10 new coal gasification plants would generate more than $10 billion in new business investment in Illinois (these facilities average more than $1 billion each to construct).

- Partnering with utility companies to purchase electricity and natural gas from coal gasification plants under long-term contracts will help stabilize natural gas and electricity prices for consumers.

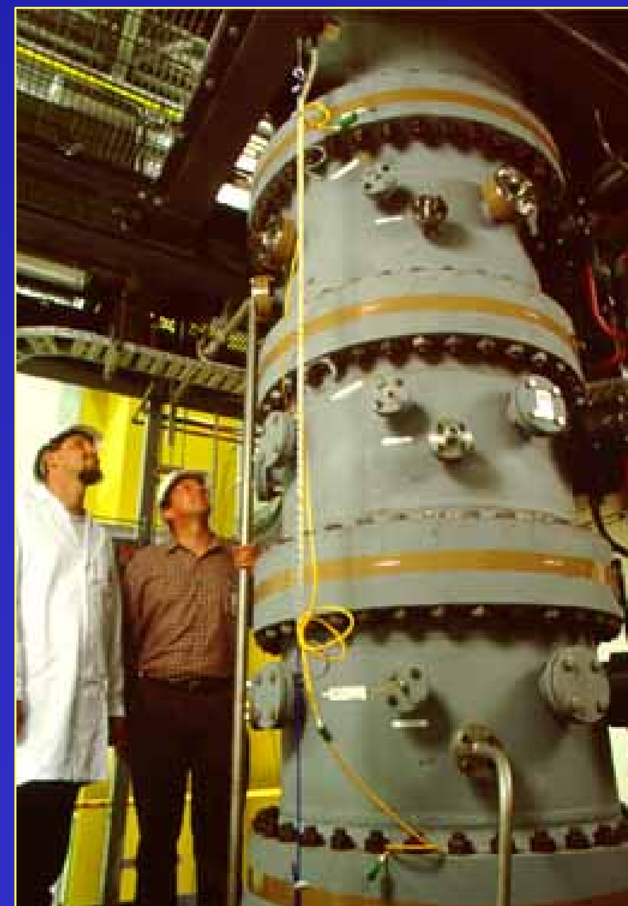
- We will encourage large corporate and government fleets to buy diesel fuel produced by coal gasification plants.

Coal Gasification Creates Jobs

- Ten coal gasification plants would use enough coal to nearly double the amount of coal mined in Illinois.

- These plants would create about 1,000 new permanent jobs at the plant, 2,500 new coal mining jobs, and 10,000 construction jobs throughout Central and Southern Illinois.

- Winning the FutureGen project would create an additional 150 permanent jobs in Illinois.



Part 4:

Reduce Air Pollution & Recover More Oil and Gas

Reduce Air Pollution

- Ethanol and biodiesel burn cleaner than gasoline or diesel made from oil.
- Fueling new ethanol and biodiesel plants with natural gas produced by coal gasification plants will reduce air pollution from biofuels facilities.
- Plant materials and by-products known as biomass can be used along with coal to co-fire power plants and coal gasification plants to reduce emissions.

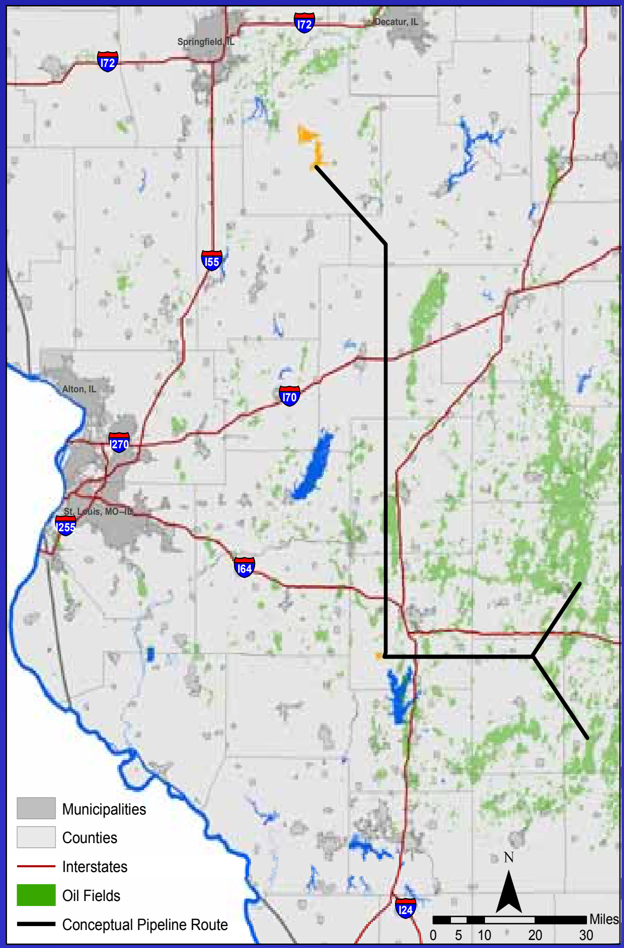
Capture & Store Greenhouse Gases

- Traditional power plants create environmental problems by producing significant amounts of carbon dioxide (CO_2), the source of 84% of emitted greenhouse gases.

- New coal gasification technology allows us to capture CO_2 rather than releasing it into the atmosphere.

- Captured CO_2 can be transported by pipeline to locations where it can be safely stored underground, preventing this greenhouse gas from escaping into the atmosphere.

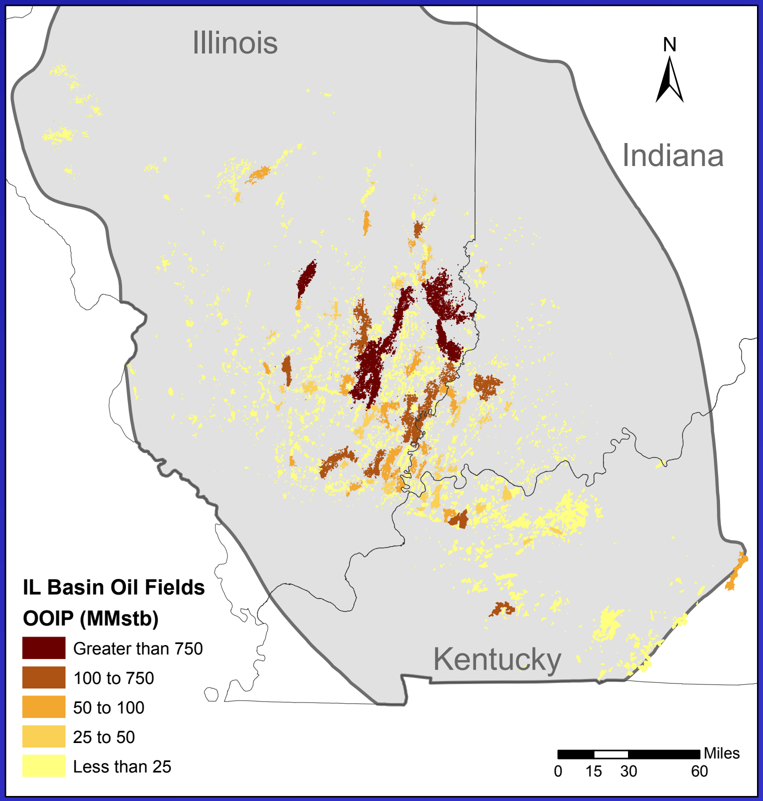
Conceptual CO2 Pipeline Route From Coal Gasification Plants to Illinois Oil Fields



Our Untapped Oil Supply

- Illinois' oil reserves hold about 1 billion barrels. Because Illinois oil fields are mature, we cannot increase production without using costly recovery techniques.

- Enhanced Oil Recovery, which uses CO2 to extract more oil from existing reserves, could double the amount of petroleum produced by Illinois annually, using CO2 that would otherwise cause global warming. The CO2 used to extract the oil stays safely trapped underground.



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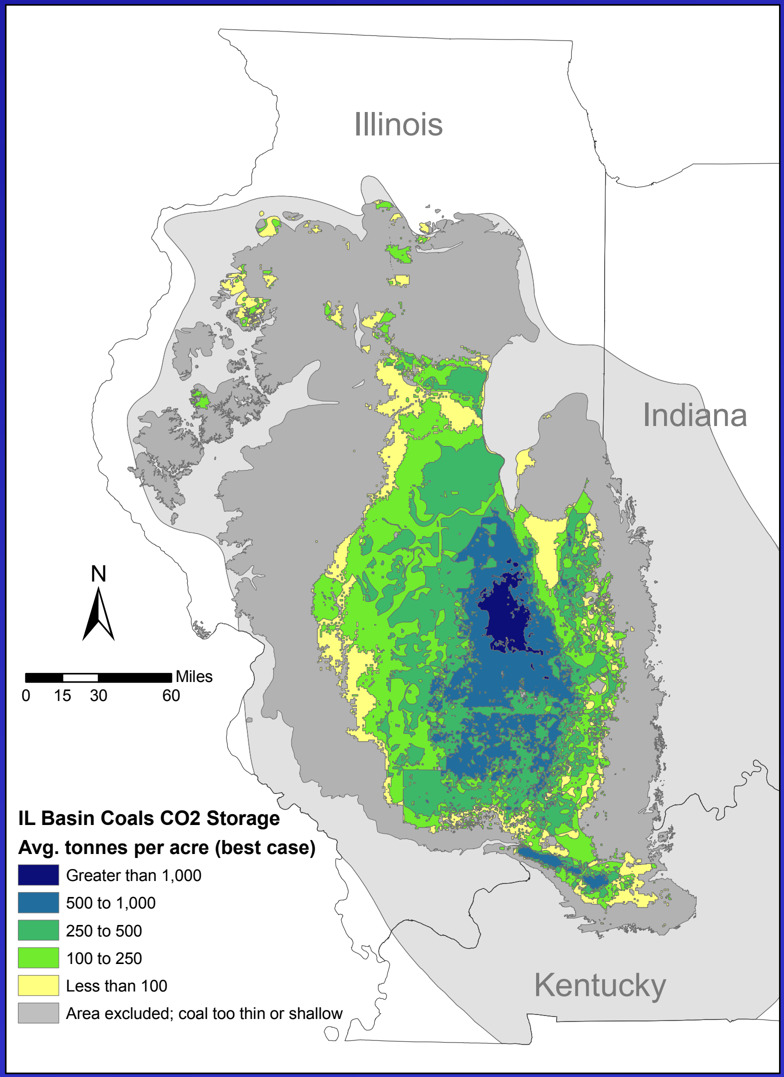
The Illinois CO2 Pipeline

- We will work with coal gasification facilities, pipeline operators and oil producers to construct a pipeline to transport CO2 produced at gasification facilities for storage underground.
- Some of this CO2 will be used by oil producers to perform Enhanced Oil Recovery (EOR) on Illinois oil fields, increasing the amount of oil we can produce.
- Because petroleum producers will pay for the CO2 necessary to extract more oil, we will partner with a private operator to maintain a 100 mile pipeline from gasification facilities to oil fields in southeastern Illinois at no annual cost to the State, using any excess proceeds to subsidize the sequestration of excess CO2.
- A similar pipeline operated to provide CO2 to oil producers for EOR is currently being profitably operated in Texas and New Mexico by a private pipeline operator.
- A 100 mile pipeline from central Illinois to the oil fields of southeastern Illinois would cost $100 million to build, but is estimated to generate more than $12 million annually in revenue.

Our Untapped Natural Gas Supply

- Illinois' coal reserves hold enough methane (a gas very similar to natural gas) to meet all of our natural gas needs for seven years.

- We will also extract methane by pumping CO2 transported by the pipeline to force out methane and permanently store CO2.



Part 5:
Reduce Energy Use, Improve Efficiency, Invest in Renewable Energy

Reducing Vehicle Emissions & Conserving Fuel

- Another major cause of greenhouse gas emissions comes from the gasoline in our cars. Consuming more fuel, whether due to long commutes or inefficient cars, hurts the environment and costs drivers more money.

- To improve air quality, reduce global warming and make Illinois more energy efficient, we will aim to reduce pollution from vehicles and reduce motor fuel consumption in Illinois by 10% by 2017, a goal which could allow Illinois residents to save billions every year in fuel costs.

- We will work with the automobile industry, environmental groups and consumer advocates to form the Illinois Fuel Conservation Task Force, which will explore strategies to reduce fuel use by 10% in 2017.

Promoting Driving Alternatives

Ways to reduce fuel consumption that the Task Force will consider will include:

- Increasing investment in public transportation through the proposed capital budget, and improve coordination among transit agencies to achieve better service.
- Providing incentives to promote carpooling and car sharing and encourage biking and walking by incorporating bike and pedestrian lanes into IDOT road projects.
- Promoting efforts to reduce suburban sprawl by encouraging new development near public transit stations.

Improve Energy Efficiency

- Conserving energy by improving the energy efficiency of Illinois' homes, businesses and public buildings is the most cost-effective way to reduce energy use and lower utility bills.

- Adopting an Energy Efficiency Portfolio Standard to greatly increase investments in energy saving programs and technologies will reduce energy use, cut utility bills and improve reliability of the energy grid.

- Public buildings are a major user of energy in Illinois. We will create a $25 million revolving loan fund to support energy efficiency investments in public buildings to reduce government energy usage.

- Illinois businesses use nearly half of all energy consumed in Illinois. We will create a $25 million revolving loan fund to support energy efficiency investments by small businesses and manufacturers.

- We have already adopted a commercial building code to ensure that new commercial and multi-family residential buildings are energy efficient. We propose adopting a similar code to ensure that new single family homes also meet modern energy efficiency standards. 42 other states have already adopted such building codes.

Invest in Renewable Electricity

- Today Illinois generates 50% of our electricity from nuclear power, 46% from coal, 2% from natural gas and less than 2% from renewable sources like wind.

- Adopting a Renewable Portfolio Standard will greatly boost use of renewable electricity in Illinois. By 2015, we can generate 10% of our electricity from clean, renewable energy sources like wind power.

- Adopting a Renewable Portfolio Standard will greatly boost use of renewable electricity in Illinois. By 2015, we can generate 10% of our electricity from clean, renewable energy sources like wind power.

Conclusion

- Unless we act now as a state to solve our energy crisis, prices will continue to rise and too many dollars will continue to flow out of Illinois if we remain dependent on imported energy.
- With the right planning, vision and leadership, we can make Illinois less reliant on foreign oil and gas by meeting a large portion of our fuel needs here at home.
- By reducing energy consumption in our homes, businesses, public buildings, and vehicles, we can protect the environment and save consumers money.
- We can't wait for the federal government. We can harness Illinois' vast natural resources to stabilize energy prices and give customers a real alternative if we are willing to act.

Paying for the Plan

What the Plan will Cost

The Energy Plan includes new programs, self-funded programs and programs funded with existing operations.

New programs include:

New Programs	New Spending	Annual Cost
Coal Gasification (Startup costs)	$175 million	$16 million
Biodiesel	$25 million	$2 million
Automakers' Incentives	$25 million	$2 million
E-85 Station Conversions	$30 million	$2 million
Energy Efficiency Revolving Funds	$50 million	$5 million
Total	**$305 million**	**$27 million**

What the Plan will Cost

The Energy Plan includes new programs, self-funded programs and programs funded with existing operations.

Existing and self-funded programs include:

Existing/Self-Funded Programs	Total Spending	Annual Cost
Coal Gasification	$600 million	Self-Funded (by coal sales tax revenues)
CO2 Pipeline	$100 million	Self-Funded (by CO2 pipeline transport fees)
Ethanol Plant Grants	$100 million	Existing Budget
Cellulosic Ethanol	$100 million	Existing Budget
Ethanol Research/Permitting	$5 million	Existing Budget
Total	**$905 million**	

Funding the Plan through Enhanced Tax Revenues

- Every year, some taxes owed to the state are never collected. The Department of Revenue estimates that businesses owe up to $40 million in sales and corporate income taxes to the State. Some businesses collect sales taxes from customers but don't remit that revenue to the State. Others, mainly out of state corporations, illegally shelter income that goes uncollected.

- The Department of Revenue is hiring 150 more tax auditors to collect these delinquent taxes, producing more than $30 million in Fiscal Year 2007, and as much as $40 million in Fiscal Year 2008.

- This revenue will be used to cover the debt service and operating costs associated with the Governor's energy plan.

- These new revenues will help ensure tax fairness and be collected without raising income or sales taxes or changing Illinois' tax code.

First Steps to Achieving Our Goals

- Hold a Governor's Energy Summit with state and elected officials and leaders from the agricultural, coal, biofuels, utilities, renewable energy, auto, and financial industries to launch our plan.
- Form the Illinois Clean Car and Energy Conservation Task Force to identify methods to reduce vehicle emissions and fuel use by 10% in 2017 as well as identify other energy-saving strategies.
- Create the Biofuels Investment & Infrastructure Taskforce.
- Issue an Executive Order to expedite state grants and permits for proposed biofuels and gasification plants.
- Work with legislative leaders and the General Assembly to secure strong state support for biofuels, coal gasification and for adoption of renewable energy and energy efficiency portfolio standards.

Report #:DOE/EIA-0554(2006)
Release date: March 2006
Next release date: March 2007

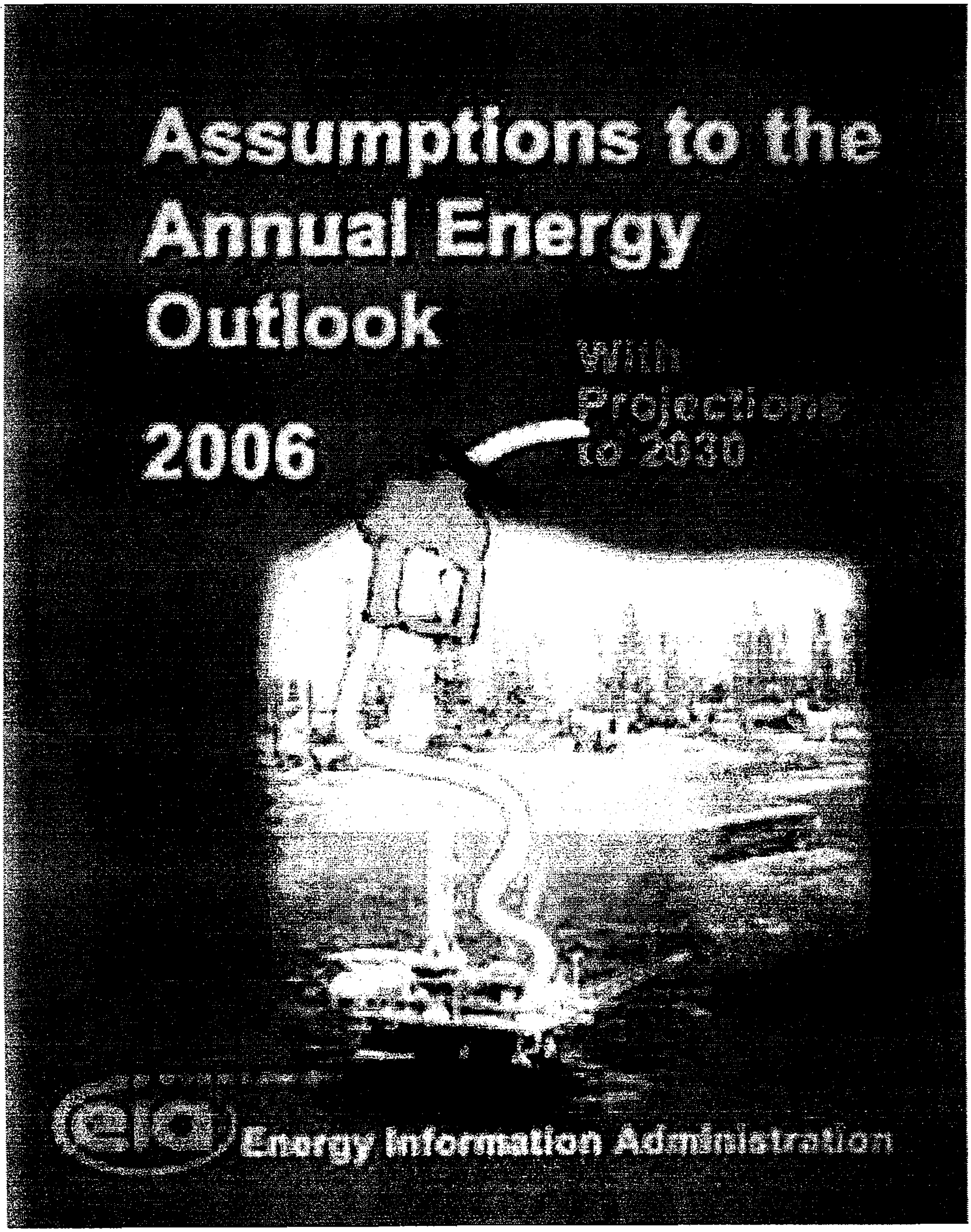


Table 38. Cost and Performance Characteristics of New Central Station Electricity Generating Technologies

Technology	Online Year[1]	Size (mW)	Leadtimes (Years)	Base Overnight Costs in 2005 ($2004/kW)	Contingency Factors: Project Contingency Factor	Contingency Factors: Technological Optimism Factor[2]	Total Overnight Cost in 2005[3] (2004 $/kW)	Variable O&M[5] ($2004 mills/kWh)	Fixed O&M[5] ($2004/kW)	Heatrate in 2005 (Btu/kWhr)	Heatrate nth-of-a-kind (Btu/kWr)
Scrubbed Coal New[7]	2009	600	4	1,167	1.07	1.00	1.249	4.18	25.07	8,844	8,600
Integrated Coal-Gasification Combined Cycle (IGCC)[7]	2009	550	4	1.349	1.07	1.00	1,443	2.65	35.21	8,309	7,200
IGCC with Carbon Sequestration	2010	380	4	1,873	1.07	1.03	2,065	4.04	41.44	9,713	7,920
Conv Gas/Oil Comb Cycle	2008	250	3	556	1.05	1.00	584	1.88	11.37	7,196	6,800
Adv Gas/Oil Comb Cycle (CC)	2008	400	3	532	1.08	1.00	575	1.82	10.65	6,752	6,333
ADV CC with Carbon Sequestration	2010	400	3	1,021	1.08	1.04	1,147	2.68	18.12	8,613	7,493
Conv Combustion Turbine[5]	2007	160	2	388	1.05	1.00	407	3.25	11.03	10,842	10,450
Adv Combustion Turbine	2007	230	2	367	1.05	1.00	385	2.89	9.59	9.227	8,550
Fuel Cells	2008	10	3	3,787	1.05	1.10	4,374	43.64	5.15	7,930	6,960
Advanced Nuclear	2013	1000	6	1,744	1.10	1.05	2,014	0.45	61.82	10,400	10,400
Distributed Generation -Base	2008	2	3	791	1.05	1.00	831	6.49	14.60	9,650	8,900
Distributed Generation -Peak	2007	1	2	951	1.05	1.00	998	6.49	14.60	10,823	9,880
Biomass	2009	80	4	1.659	1.07	1.02	1,809	3.13	48.56	8,911	8,911
MSW - Landfill Gas	2008	30	3	1,443	1.07	1.00	1,544	0.01	104.03	13,648	13,648
Geothermal[6,7]	2009	50	4	2.100	1.05	1.00	2,205	0.00	75.00	32,173	35,460
Conventional Hydropower[6]	2009	500	4	1,320	1.10	1.00	1,452	3.20	12.72	10,338	10,338
Wind	2008	50	3	1,091	1.07	1.00	1.167	0.00	27.59	10,280	10,280
Solar Thermal[7]	2008	100	3	2.589	1.07	1.10	3.047	0.00	51.70	10,280	10,280
Photovoltaic[7]	2007	5	2	3,981	1.05	1.10	4,598	0.00	10.64	10,280	10,280

[1]Online year represents the first year that a new unit could be completed, given an order date of 2005.

[2]The technological optimism factor is applied to the first four units of a new, unproven design, or regulatory structure. It reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[3]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2005.

[4]O&M = Operations and maintenance.

[5]Combustion turbine units can be built by the model prior to 2007 if necessary to meet a given region's reserve margin.

[6]Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

[7]Capital costs are shown before investment tax credits are applied.

Sources: The values shown in this table are developed by the Energy Information Administration, Office of Integrated Analysis and Forecasting, from analysis of reports and discussions with various sources from industry, government, and the Department of Energy Fuel Offices and National Laboratories. They are not based on any specific technology model, but rather, are meant to represent the cost and performance of typical plants under normal operating conditions for each plant type. Key sources reviewed are listed in the 'Notes and Sources' section at the end of the chapter.

IR-CFB Repowering: A Cost-Effective Option for Older PC-Fired Boilers

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Abstract

Worldwide, many older Pulverized Coal (PC) fired boilers (25-35 years) are in operation. Performance of these boilers deteriorates over time due to poor fuel quality. Some of the units are derated because of the varying fuel conditions (such as moisture, ash, sulfur and heating value), pulverizer limitations, erosion related issues, and environmental considerations.

Upgrading of the existing aged PC-fired boilers is one of the urgent needs in most countries because of economic and environmental pressures. Internal Recirculation Circulating Fluidized Bed (IR-CFB) repowering will address fuel related issues as well as current emission requirements and has the potential to extend the life of an older plant for another 20-25 years. B&W has completed extensive repowering feasibility studies of various PC-fired boilers for customers in the U.S.A., China, India, Ukraine and Thailand. These studies clearly show that IR-CFB repowering is an economically viable option to utilize existing fuel or low grade fuel, reduce emissions, eliminate high maintenance pulverizers and reduce auxiliary support fuel (oil/gas) consumption. This paper presents Babcock & Wilcox (B&W) IR-CFB boiler repowering findings for selected projects including design and performance summaries, PC vs. CFB comparison, emission performance, and technical and economic benefits.

Introduction

World demand for electric power continues to rise steeply, as a result of three main factors: population growth, economic development, and progressive substitution of alternate fuels coupled with clean forms of energy. Power plant operators place major importance on high plant efficiency and low fuel consumption. The average plant efficiency of all coal-fired power plants in operation today is around 33 percent. One of the important tasks facing the power industry is upgrade of the existing power plants.

Upgrading of the existing aged PC-fired boilers is one of the urgent needs in most countries because of the economic and environmental pressures. Many PC-fired boilers installed in the 1960s and early 70s require pressure parts replacement, high pulverizer maintenance, large quantity of oil/gas auxiliary fuel up to 50-60% MCR load, and many suffer from reduced output due to deterioration of fuel quality. These units also produce high emission levels.

Babcock & Wilcox is a leading global supplier of industrial/utility boilers and has supplied more than 700 units totaling more than 270,000 MWe. Understanding the operation and maintenance complexity of the aged PC-fired boilers, B&W has applied its inherently compact, distinctive internal recirculation circulating fluidized bed boiler (IR-CFB) featuring U-beam solids separators. The furnace and convection pass of the IR-CFB boiler are enclosed in a single, gas–tight membrane enclosure as commonly found in PC-fired boilers. Many of the boiler design features have been adapted from B&W's long experience designing and building boilers of all types and sizes for industrial and electric utility applications. This compact, integral design allows economical retrofit of aged PC-fired boilers with CFB technology which will fit into the existing PC-fired boiler support steel. This technology has been successfully introduced in the global market.

While IR-CFB technology is a viable long term solution for upgrading of power plants and for burning low grade fuels, PC-fired boilers will continue to produce most of the coal-based electric power for years to come. The objective of IR-CFB repowering is to replace the existing PC-fired boilers economically in an environmentally acceptable manner, to extend the plant life for another 20-25 years, and to provide fuel flexibility.

To date, B&W, including B&W joint ventures and licensee companies, have sold more than 18 CFB boilers worldwide, shown in Table 1. B&W offers IR-CFB boilers to over 175 MWe, both reheat and non-reheat with full commercial guarantees and warranties. The IR-CFB boiler is simple in configuration and compact, requires a smaller boiler footprint, has minimal refractory, requires low maintenance, features quick start up and provides high availability.

IR-CFB Repowering Approach

B&W is actively involved in working on several IR-CFB repowering projects in various countries. Four IR-CFB repowering feasibility studies are considered for this paper. The objectives of IR-CFB repowering are**:**

- Increase MW output to rated capacity
- Burn poor quality domestic fuels (provide fuel flexibility)
- Increase boiler and plant efficiencies and thus improve heat rate
- Reduce operating and maintenance cost
- Meet current emission requirements (SO_2 and NO_x)
- Economically replace existing boilers with minimum downtime
- Extend existing plant life (possibly 20-25 years)
- Utilize the existing plant to minimize capital cost
- Reduce some of the approval and permitting process

PC vs. CFB Technology Comparison

Designers and power plant operators have much experience in PC-fired boiler design and operations. Adapting and understanding the CFB technology in the PC environment requires time. CFB technology brings the capability of designs for a wide range of fuel (from low quality to high quality fuels), lower emissions, elimination of high maintenance pulverizers, low auxiliary fuel support and lower life cycle costs. PC vs. IR-CFB comparison is given in Table 2.

The combustion temperature of a CFB [840 to 900C (1550 to 1650F)] is much lower than PC [1350 to 1500C (2450 to 2750F)] which results in lower NO_x formation and the ability to capture SO_2 with limestone injection in the furnace. Even though the combustion temperature of CFB is low, the fuel residence time in CFB is higher than PC, which results in combustion efficiencies comparable to PC. The PC pulverizers, which grind the coal to 70% less than 75 microns, require significant maintenance expenses. These costs are virtually minimized in CFB because the coal is crushed to 12 to 6 mm (0.5 to 0.25 in.) x 0 size. Even though CFB boiler equipment is designed for relatively lower flue gas velocities, the heat transfer coefficient of the CFB furnace is nearly double that of PC which will make the furnace compact. In an IR-CFB, auxiliary fuel support is needed for cold start up and operation below 25% versus 40-60% MCR with PC. One of the most important aspects is that

Table 1
B&W Circulating Fluidized-Bed Boiler Experience
Including B&W Joint Ventures and Licensees

Start-up Date	Customer Name & Plant Location	Unit Type	No. of Units	Steam Output, TPH	Thermal Output, MW_t	Fuels
1986	Ultrapower West Enfield, Maine, U.S.A.	CFB	1	100	77.0	Wood wastes & wood chips
1986	Ultrapower Jonesboro, Main, U.S.A.	CFB	1	100	77.0	Wood wastes & wood chips
1986	Sithe Energy Marysville, California, U.S.A.	CFB	1	74	58.0	Wood wastes
---	Los Angeles County Sanitation Dist. Carson, California, U.S.A.	CFB	3	22	16.0	Sewage sludge
1989	Lauhoff Grain Company Danville, Illinois, U.S.A.	CFB	1	102	79.0	Bituminous coal, petroleum coke
1990	Ebensburg Power Co. Ebensburg, Pennsylvnia, U.S.A.	CFB	1	237	172.0	Waste coal
1991	Pusan Dyeing Company Pusan, Republic of Korea	CFB	2	80	58.0	Coal & heavy fuel oil
1993	Thai Petrochemical Industries Rayong, Thailand	CFB	1	136	93.0	Coal, lignite, petroleum coke, heavy fuel oil
1996	Southern Illinois University Carbondale, Illinois, U.S.A.	CFB	1	54	35.0	Coal, petroleum coke & natural gas
1997	Kanoria Chemicals, Ltd. Renukoot, India	CFB	1	105	81.0	High ash coal
2000	Anshan Co-Generation Plant Anshan, Liaoning, P.R. China	CFB	2	75	55.0	Bituminous coal
2001	AES Beaver Valley Monaca, Pennsylvania, U.S.A.	CFB	1	163	121.5	Bituminous coal
2001	Changguang Coal Mine Co. Zhejiang Province, China	CFB	1	220	155.0	High sulfur bituminous
2001	Southern Indiana Gas & Electric Co. Mount Vernon, Indiana, U.S.A.	CFB	1	475	342.0	High sulfur coal, waste coal

Table 2
Benefits of a CFB Boiler Over a PC-Fired Boiler

Description	CFB Boiler	PC-Fired Boiler	Benefits of CFB
Fuel size	12-6 mm (0.5-0.25 in.) x 0	>70%<75 microns	Grinding cost is reduced
Fuel range (ash + moisture)	Up to 75%	Up to 60%	Accepts wider range
Higher sulfur fuels (1-6%)	Limestone injection	FGD plant required	Less expensive SO_2 removal system
Auxiliary fuel support (oil or gas)	Up to 20-30%	Up to 60%	Less oil/gas consumption
Auxiliary power consumption	Slightly higher	Lower	If FGD is used in PC, CFB power is lower
Emissions			
SO_2, ppm	<200	<200 with FGD	Lower emissions in process, less expensive
NO_x, ppm	<100	<100 with SCR	No SCR (or SNCR) system required
Boiler efficiency, %	Same	Same	No difference
O&M cost (80% PLF)	Lower	Higher	Lower because of less moving equipment
Capital cost	5-10% higher	5-10% lower w/o FGD & SCR	—
	8-15% lower	8-15% higher w/ FGD & SCR	—

CFB boilers release very low levels of SO_2 and NO_x pollutants compared to PC. These benefits lead owners to select CFB for repowering.

Design Features of B&W IR-CFB Boiler Technology

B&W IR-CFB technology is very compatible to PC-fired boilers in arrangement. The IR-CFB boiler design consists of the following major systems, shown in Figure 1. The main boiler components are:

- Boiler furnace
- Furnace bottom air distributor and nozzles
- Primary solids separators and recirculation system
- Secondary solids separators and recirculation system
- Pendant superheater/reheater
- Economizer and horizontal tubular air heater
- Air assisted gravity fuel/limestone feed system

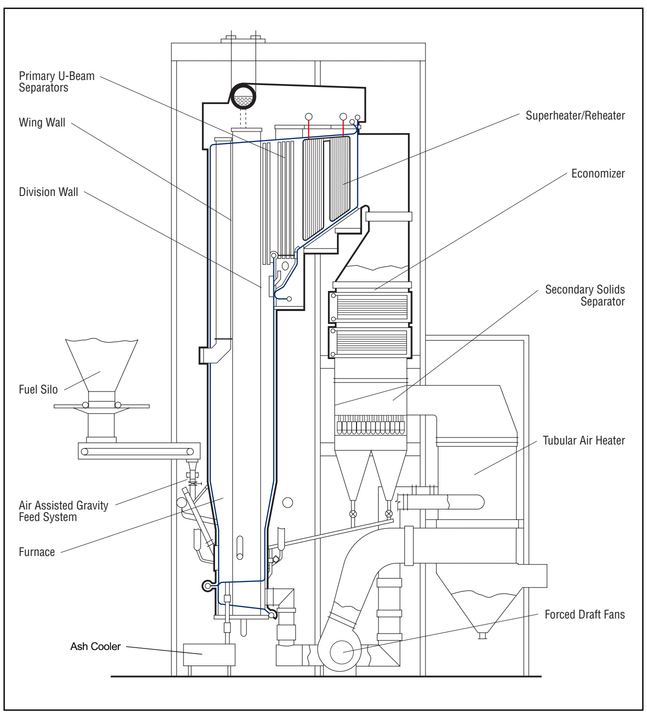

Figure 1 B&W's IR-CFB boiler.

Boiler Furnace

The furnace cross section is selected based on flue gas superficial velocity. B&W typically uses a 3.7 m, 4.6 m and 5.4 m (12, 15 and 18 ft) deep furnace. The furnace enclosure is made of gas-tight membrane water-cooled walls having 63.5 mm or 76 mm (2.5 or 3 in.) tube diameter on 102 mm (4 in.) centers. The furnace primary zone is reduced in plan area cross section to provide good mixing and promote solids entrainment at low load. The auxiliary start-up burners, fuel feed points and secondary ash re-injection (multicyclone/MDC) points are located in this region.

A thin layer of refractory is applied on all lower furnace walls, including the lower portion of the division walls and wing walls nose to protect against corrosion and erosion. An ultra high strength abrasion-resistant low cement alumina refractory 16 to 25 mm (0.625 to 1 in.) thick is applied over a dense pin studded pattern. The furnace temperature is precisely controlled by maintaining proper inventory and thus the combustion efficiency and the limestone utilization are maximized.

Air Distributors and Nozzles

The furnace bottom air plenum or wind box is made of water-cooled panels or casing depending on start-up air temperature. Bubble caps are fitted on the water-cooled distributor floor panels as shown in Figure 2. The bubble caps are designed to distribute air uniformly, prevent the back sifting of solids at low load operation, and create good turbulence for fuel /sorbent mixing in the primary zone. The bubble caps are spaced 102 mm x 117 mm (4 x 4.5 in.) with 60-70% of total combustion air admitted through the bottom. The balance 30-40% of total air is admitted through overfire nozzles (high velocity) in the front and rear furnace walls.

Primary Solids Separators

The solids separation system is a key element of any CFB boiler design, influencing life cycle costs. The B&W IR-CFB has a two stage primary solids separator as shown in Figure 3, comprised of in-furnace U-beam separators and external U-beam separators. The in-furnace U-beams (two rows) are able to collect nearly 75% of the solids. The remaining solids collected by the three or four rows of external U-beams and are discharged from the hopper directly into the furnace through the transfer hopper located beneath the external U-beams. The flue gas velocity across the U-beams is approximately 8 to 10 m/s (28 to 30 ft/s), limiting the gas side pressure drop to 0.25 kPa (<0.5 in.

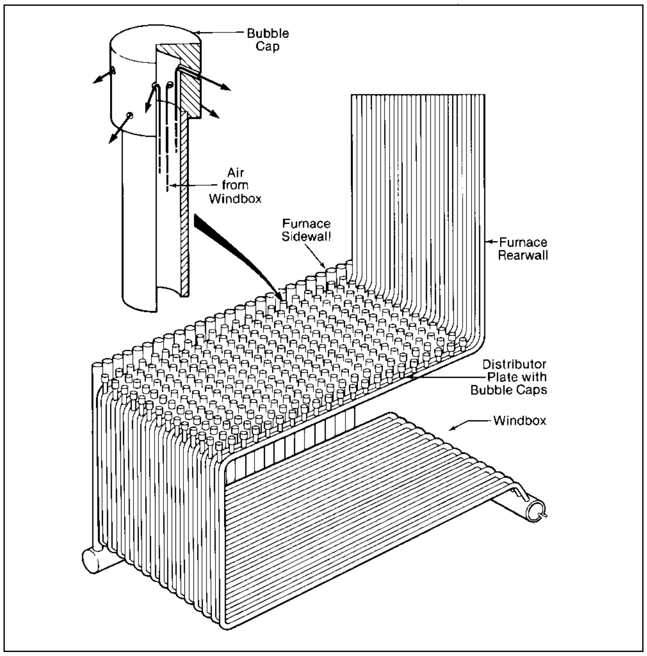

Figure 2 Furnace distributor floor panel and bubble caps.

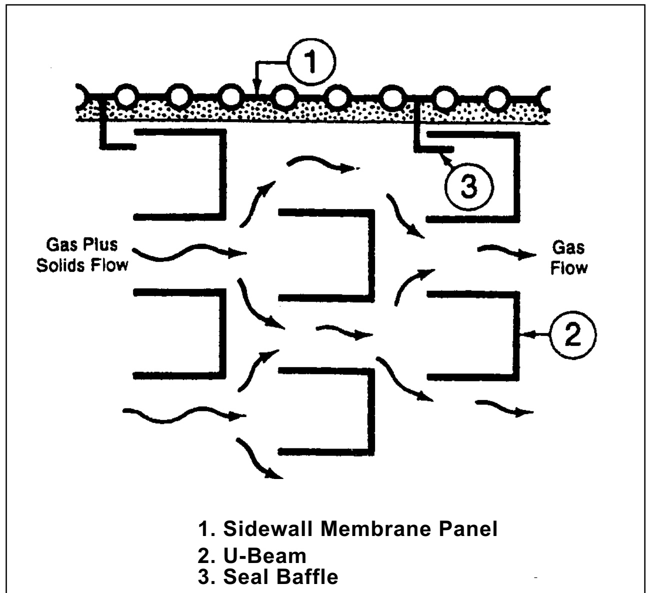

Figure 3 U-beam primary separators—plan view.

wc) as compared with a typical cyclone separator's pressure drop of 1.5 to 2.0 kPa (6 to 8 in. wc). A commercially available, high-grade stainless steel material is utilized for the U-beam separators.

Secondary Solids Separator

The multicyclone (MDC) is located in the convective pass either upstream or downstream of the economizer. The MDC typically has a top inlet and top outlet as shown in Figure 4. The MDC tube diameter is normally 229 mm (9 in.) arranged over the second pass entire cross-section. The MDC provides outstanding retainment of fine particles up to 50 microns (>95%). The MDC collection tubes and spin vanes have high hardness (550 BHN), designed for longer life and easy replacement during planned outages.

The small quantity of fines which escape from the external U-beams is collected by the MDC. The collected fines are stored in the MDC hopper. Variable speed rotary feeders or inclined screws are used to control the ash recycle flow rate from the hopper. Precise furnace temperature control is achieved by adjusting the speed of the rotary feeders or inclined screws, taking the temperature signal from the furnace.

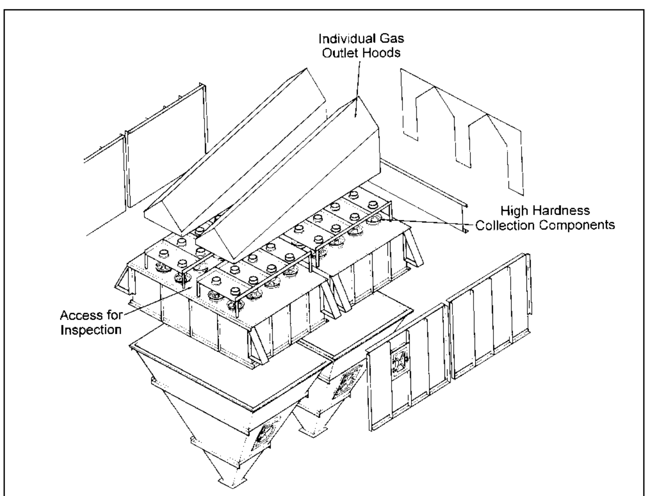

Figure 4 Multicyclone dust collector.

Pendant Type Superheater/Reheater

The superheater may consist of vertical pendant type primary and secondary banks, located in the convection pass, as well as surface in the furnace in the form of superheater wing walls. An attemperator is used to control the final steam temperature over the design load range. The flue gas velocities are selected by considering the dust loading and ash erosivity of the fuel. The reheater is located in the convection pass and proper temperature control method is applied to control the final reheater temperature.

Economizer and Horizontal Tubular Air Heater

The economizer is designed with tubes running front to back and in-line, with reasonable flue gas velocities by considering the dust loading and ash erosivity of the fuel. Both the economizer and the air heater are located in-line to minimize ash fouling if the MDC is located upstream of the economizer. The air heater is located after the MDC and the economizer. The flue gas is outside the tubes and air is passed through the tubes. A hopper is provided at the bottom of the air heater and the ash collected in the hopper is purged to the ash disposal system. The tube material and flue gas velocities are selected by considering the dust loading and the ash erosivity of the fuel. A steam coil air heater (SCAH) is used to protect the cold end of the air heater if required.

Air Assisted Gravity Fuel/Limestone Feed System

Fuel handling and feeding is one of the major challenges in CFB boiler operation, especially with waste fuels because of high fines and moisture content. The crushed fuel [12 mm (0.5

in.) x 0] is stored in the silo, usually located in front of the boiler as shown in Figure 5. Fuel is fed to the boiler via down spout from silo discharge to feeder and a series of feeders and gravity feed chutes. The fuel chute will have at least a 60 to 65 degree angle from horizontal. Primary air is used to sweep the fuel into the furnace and as seal air to the feeders. The number of feed points is set to achieve even fuel distribution in the furnace.

The limestone handling and feeding system is relatively simple compared to the fuel feed system. Limestone is fed either pneumatically or mechanically into the CFB boiler. The pneumatic system feeds the limestone directly into the furnace through furnace openings in the front and rear walls. In the mechanical system, the limestone is fed into the discharge end of the fuel feeders via rotary feeders. The limestone falls by gravity down the fuel feed chute with the fuel into the furnace.

IR-CFB Boiler Repowering

50 MW Older PC-Fired Boiler—IR-CFB Repowering Study—Ukraine

This feasibility study was done for a typical 50 MW PC-fired boiler in Ukraine. This boiler, built in 1950, a typical PC-fired boiler TP-230, was manufactured by Taganrog Boiler Works, Russia and is experiencing the following problems:

- The fuel quality has deteriorated [from 6,200 to 4,250 kcal/kg (11,160 to 7,650 Btu/lb)] due to increase in ash content and thus tremendous amounts of oil and natural gas are being used as supplemental fuels.
- The fuel currently available in the Ukraine is high-ash anthracite (called schtib), not favorable for burning in the existing PC-fired boiler.
- The PC-fired boilers are aged and require refurbishment for continuing operation.
- None of the existing PC boilers has a means of SO_2 and NO_x emission control.
- Extending the life of the existing plant is required.

The addition of coal-based generation capacity will be done mainly through repowering and rehabilitation of the existing power plants. The Ukraine power industry is facing the challenges of maximizing power generation from coal, improving efficiency of coal utilization, improving the reliability and maintainability of the existing older units and reducing air pollution from coal-fired power plants. To achieve these goals, CFB repowering is considered to be a viable option for 50 MW, 125 MW and 200 MW units in Ukraine.

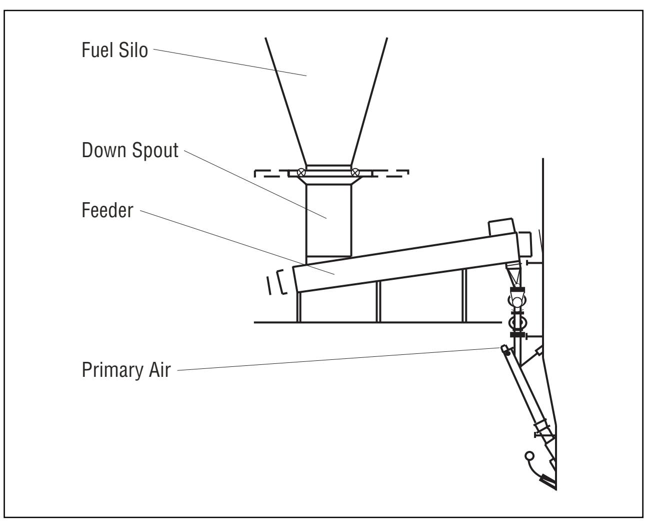

Figure 5 IR-CFB gravity feed chutes.

This feasibility study included test firing of the coal in B&W's 2.5 MW IR-CFB test facility and designing the IR-CFB boiler for repowering. Both were successfully accomplished. The project is currently on hold for lack of funding. The fuel and steam conditions are given in Table 3. The boiler preliminary design details including emissions are given in Table 4.

The arrangement of the 50 MW IR-CFB boiler is shown in Figure 6. The B&W IR-CFB boiler fits within the footprint of the existing boiler plan area, but furnace height needs to be increased by 7 m (23 ft) for efficient combustion of high-ash coal. The addition of boiler columns and top steel would need to be installed to support the boiler.

A secondary coal crusher and limestone crushers should be added in the existing central location with coal and limestone transported to the boiler using existing conveyors. The crushed coal can be stored in the existing coal bunkers, previously used for raw coal. Two new fuel feeders will be used for feeding the coal. The coal will be fed to the boiler in four points through the front furnace wall using gravity feed chutes. Limestone will be stored in an existing coal bunker and will be fed pneumatically through the front and rear furnace walls. MDC and secondary ash recycle system would be added. Bed ash will be drained from the furnace via three water-cooled screws. A baghouse or electrostatic precipitator (ESP) will be installed for particulate control. A new dry ash handling system will be installed in place of the plant's existing wet sludge system which can not be used due to the presence of unreacted lime in the bed solids.

100 MW Older PC-Fired Boiler—IR-CFB Repowering Study—China

B&W and BWBC, a joint venture company of B&W in China, have jointly investigated IR-CFB boiler repowering for a 100 MW PC-fired boiler in China. This particular boiler was installed in 1976. The unit is operating between 70 and 80 MW output. The plant is equipped with two ball mills, and an indirect firing system. The crushed coal is stored in the concrete bunkers. The boiler is a tangentially fired type, with wet bottom ash removal system, water screen cyclone separators and no pollution control devices. Some of the major issues involved are:

- The fuel quality has deteriorated. The fuel ash is highly erosive and frequent tube failures and replacement are taking place.
- Frequent ID fan erosion occurs due to poor particle collection efficiency of water screen cyclone separators.
- The sulfur content has increased from 0.81% to 1.63 % and SO_2 emission is high.
- SO_2, NO_x and PM emissions are very high. Recently, China has introduced a SO_2 penalty for thermal power plants.
- Operation and maintenance cost has significantly increased.
- In general, the boiler performance has been reduced over time.

The plant is looking for a CFB boiler that will fit into the existing support steel due to the space restriction at the plant. B&W has evaluated whether or not the IR-CFB will fit into the existing support steel frame. The evaluation indicated that the IR-CFB boiler will fit into the existing support steel as shown

Table 3
Fuel Data and Steam Conditions

Description **Type of Fuel**	**Ukraine, 50 MW** **Anthracite**	**China, 100 MW** **Semi-Anthracite**	**USA, 136 MW** **Petroleum Coke**	**India, 140 MW** **Bituminous Coal**
Proximate analysis				
Moisture, % weight	10.0	7.33	9.25	8.90
Volatile matter, % weight	4.0	10.76	9.94	25.40
Fixed carbon, % weight	40.0	47.23	80.41	28.70
Ash, % weight	36.0	29.14	0.40	37.0
Ultimate analysis				
C, % weight	49.6	55.12	80.50	35.00
H, % weight	1.0	2.52	2.25	3.00
O, % weight	1.5	3.39	0.50	12.02
N, % weight	0.5	0.87	1.00	3.42
S, % weight	1.4	1.63	6.10	0.66
Ash, % weight	36.0	29.14	0.40	37.00
Moisture, % weight	10.0	7.33	9.25	8.90
Higher heating value, kcal/kg	4,059	5,100	7,500	3,300
(Btu/lb)	(7,306)	(9,180)	(13,800)	(5,940)
Steam conditions				
SH steam flow, kg/hr	230,000	410,000	453,600	428,400
(lb/hr)	(507,050)	(903,880)	(1,000,000)	(944,440)
SH steam pressure, bar	98	98	108	145
(psig)	(1,420)	(1,420)	(1,566)	(2,100)
SH steam temperature, deg. C	510	540	540	543
(deg. F)	(950)	(1,005)	(1,005)	(1,010)
RH steam temperature, deg. C	—	—	343/540	344/540
(deg. F)	—	—	(649/1,005)	(651/1,005)
RH pressures, bar	—	—	27.2/24.1	42.7/40.0
(psig)	—	—	(395/350)	(619/580)
RH steam flow, kg/hr	—	—	383,200	384,500
(lb/hr)	—	—	(844,800)	(847,660)
FW temperature, deg. C	230	220	238	252
(deg. F)	(446)	(428)	(460)	(486)

Table 4
Predicted Performance for IR-CFB Repowering

Description	**Ukraine, 50 MW**	**China, 100 MW**	**U.S.A., 136 MW**	**India, 140 MW**
Existing PC-boiler column spacing				
[width x depth], m x m	19.8 x 27.0	16.0 x 27.0	15.84 x 28.25	18.0 x 33.75
(ft x ft)	(65.0 x 88.6)	(52.5 x 88.6)	(52.0 x 92.7)	(59.0 x 110.7)
IR-CFB boiler size				
[width x depth], m x m	9.8 x 27.0	14.0 x 26.0	14.1 x 28.0	16.2 x 33.0
(ft x ft)	(32’-2” x 18’-0”)	(46’-2 x 88’-6”)	(46’-2” x 19’-6”)	(52’-2” x 18’-0”)
Fuel flow rate, kg/hr	42,930	55,660	44,993	99,950
(lb/hr)	(94,640)	(122,700)	(99,190)	(220,350)
Limestone flow rate, kg/hr	9,650	7,330	21,900	3,700
(lb/hr)	(21,270)	(16,160)	(48,280)	(8,150)
Ca/S molar ratio	2.1	2.2	2.3	1.6
Sulfur capture, %	90	90	95	55
Boiler efficiency, %	86.4	87.5	90.5	85.3
Excess air, %	20	20	20	20
Ash split (bottom/fly) ratio, %	35/65	20/80	40/60	30/70
Stack flue gas temperature, deg. C	148	140	140	140
(deg. F)	(298)	(284)	(284)	(284)
Emissions				
NO_x, ppm	<100	<100	<100	<100
SO_2, ppm	180	150	190	<220

in Figure 7. Existing components such as steam drum, downcomers, risers, support steel, coal bunkers and the coal handling system can be reused.

The new equipment required for this plant includes the IR-CFB boiler and auxiliary equipment, dry ash handling system with silo, ESP, DCS system, secondary coal crushers, limestone crushers and handling and feeding system, and support steel strengthening if required. The fuel and steam conditions are given in Table 3. The design and performance data are given in Table 4.

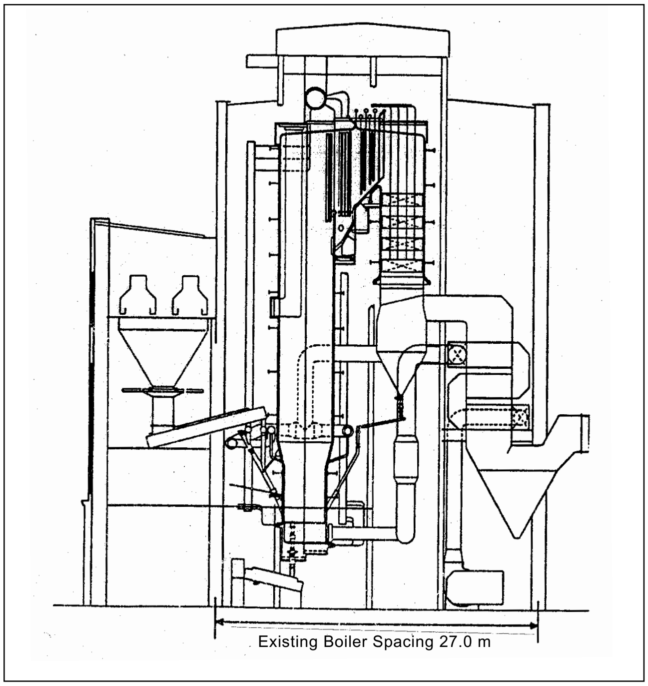

Figure 6 50 MW IR-CFB boiler repowering for high-ash anthracite fuel—Ukraine.

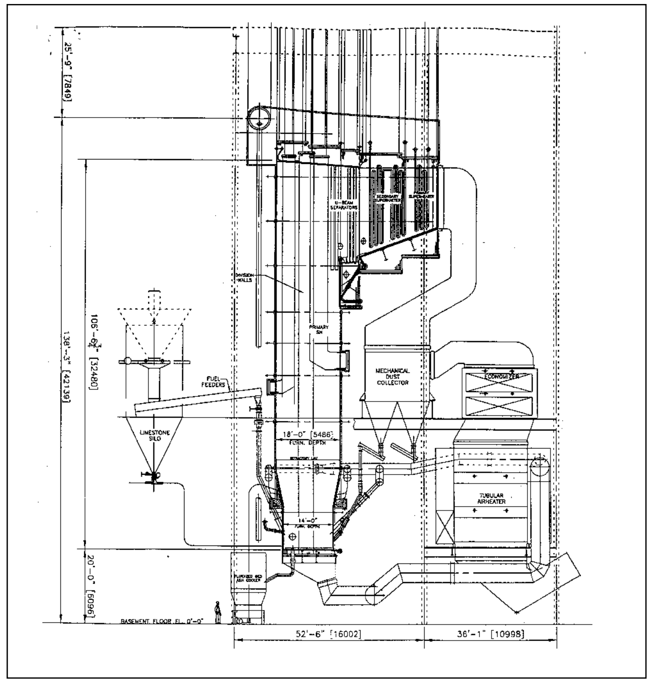

Figure 7 100 MW IR-CFB boiler repowering for high-ash semi-anthracite fuel—China.

136 MW Older Coal Fired Boiler—IR-CFB Repowering Study—U.S.A.

Yet another technical feasibility study was done for an existing 136 MW coal fired boiler in the USA. Babcock & Wilcox supplied this boiler in the 1960s, a typical front wall cyclone-fired radiant boiler for utility application. Major issues with this unit are:

- Most of the boiler equipment is aged.
- Pressure part replacements are required.
- Gas consumption is high to support boiler operation at low load.
- Plant must meet new emissions regulations (SO_2, NO_x, and PM).
- Plant is switching from coal to lower cost, high sulfur petroleum coke.

The primary objective of IR-CFB repowering is to replace the existing boiler economically by utilizing some of the existing equipment and completing the CFB repowering in a short period of time. B&W's preliminary technical evaluation indicates that its IR-CFB boiler will fit into the existing support steel, and the existing cyclone fired boiler plan area is adequate for the IR-CFB boiler.

The study indicates that existing components such as steam drum, downcomers, riser pipes, support steel, coal crushers, coal bunkers, recently replaced valves, fuel handling system and stack would be retained. B&W has estimated that IR-CFB repowering of this unit can be done within three months of plant downtime. The new equipment required at this plant includes IR-CFB boiler and auxiliary equipment, dry ash handling system, DCS system, limestone crushers, coke handling and feeding system, support steel strengthening if required and baghouse filters. The fuel and steam conditions are given in Table 3. The design and performance data are given in Table 4. The new arrangement of IR-CFB boiler with the existing support steel is shown in Figure 8.

140 MW Older PC-Fired Boiler—IR-CFB Repowering Study—India

A technical feasibility study was done for an existing 140 MW PC-fired boiler in India. This boiler was installed in 1970, supplied by Babcock in the UK. Most of the equipment is aged and unit operation is limited to an average output of 95 to 105 MW. The major problems that are being faced by the plant are:

- Tremendous amount of erosion on water wall, SH, RH and economizer tubes. This erosion is mainly due to high coal ash content with significant alpha quartz.
- High pulverizer maintenance costs.
- High oil consumption to support the boiler load.
- Low boiler efficiency because of high unburned carbon and high excess air.
- Boiler availability has deteriorated over the years.

One of the major issues is the deterioration of boiler performance attributed to the fuel quality. The existing PC-fired boiler was designed for a heating value of 5,000 kcal/kg (9,000 Btu/lb) with ash content of 28%. The present fuel quality is 3,300 kcal/kg (5,940 Btu/lb) with ash content of 37%. This poor quality coal associated with aged equipment has led to reduced boiler performance.

IR-CFB repowering is suitable to replace the existing PC-fired boiler economically by utilizing existing equipment and replacement of the PC unit with IR-CFB in a short time period. The preliminary technical evaluation indicates that the B&W IR-CFB boiler will fit into the existing support steel. The existing PC-fired boiler plan area is adequate for the IR-CFB boiler.

The existing equipment such as steam drum, downcomers, riser pipes, ESP, support steel, coal bunkers, primary coal crushers, fuel handling system and stack would be retained. B&W has estimated that IR-CFB repowering of this unit can be done in less than six months of plant downtime. The new equipment identified for this plant includes IR-CFB boiler and auxiliary

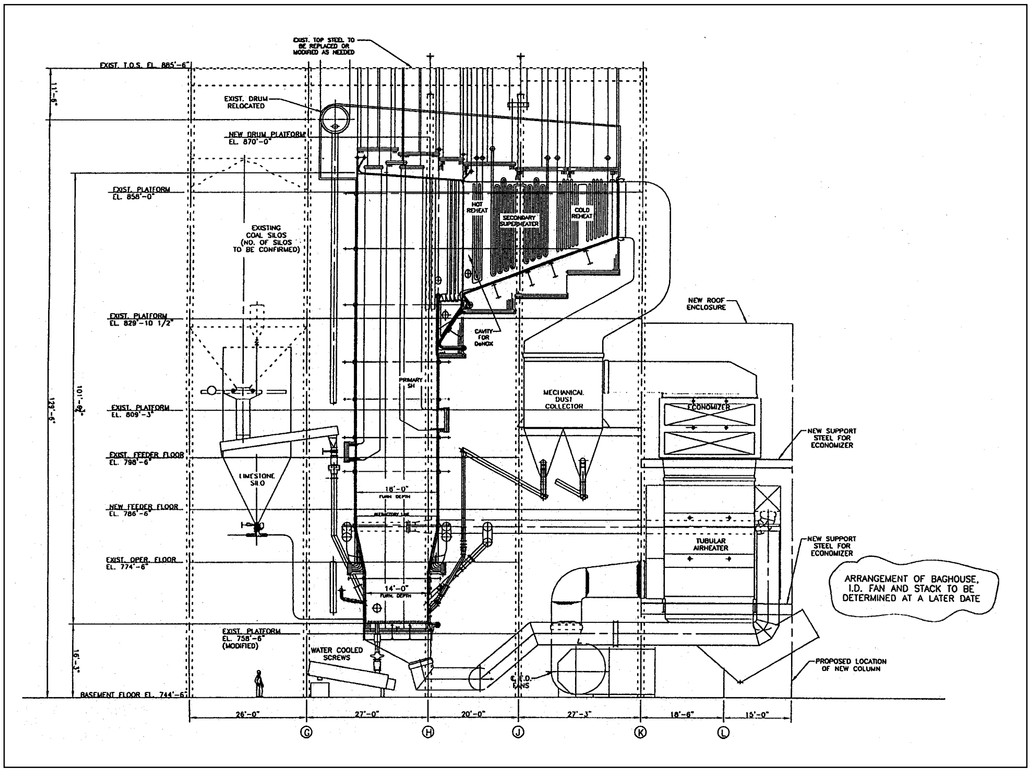

Figure 8 136 MW IR-CFB boiler repowering for petroleum coke fuel—U.S.A.

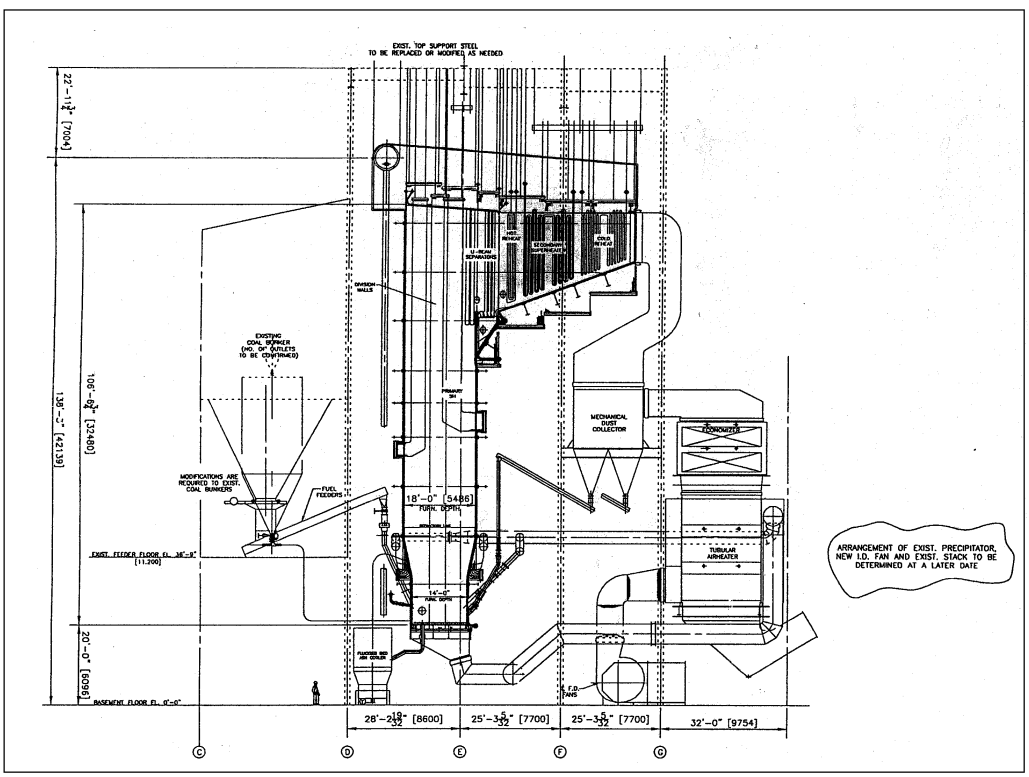

Figure 9 140 MW IR-CFB boiler repowering for high-ash coal—India.

equipment, dry ash handling system, DCS system, secondary coal crushers, limestone crushers and handling and feeding system if needed and support steel strengthening if required. The fuel and steam conditions are given in Table 3. The design and performance data are given in Table 4. The new arrangement of IR-CFB boiler with the existing support steel is shown in Figure 9.

Preliminary Economic Evaluation

Economic Benefit for IR-CFB Repowering

B&W has made a preliminary economic evaluation for all of these units. By knowing the operating and maintenance costs and power selling costs, the capital cost and payback period are established as given in Table 5. The capital costs for IR-CFB boiler repowering with balance of plant equipment vary from country to country. The average Engineer/Procure/Construct capital cost is around $250 to $300 per kw which is one-third of the new power plant cost. This cost includes the IR-CFB boiler with some new auxiliary equipment, DCS system, dry ash handling system with silo, secondary fuel crushers, limestone handling system with silo, if required, boiler dismantling, erection and commissioning. The payback period typically varies from 4 years to 6 years (with some exceptions) and is based on the existing unit's operating MWe output and the selling price of power for the existing units.

Conclusions

IR-CFB boiler technology can be successfully used for repowering the existing older PC-fired boilers. The CFB technology can handle poor quality fuel and economically return the plant to original rating with a limited downtime while meeting the current emissions requirements, providing a long-term solution for the plant. The B&W IR-CFB boiler is compact and fits into the space utilized by older PC-fired boilers, and features low maintenance costs as compared to competing cyclone based CFB designs and

Table 5
Economic Evaluation for IR-CFB Repowering

Description	Unit	Ukraine, 50 MW	China, 100 MW	USA, 136 MW	India, 140 MW
Unit rated output	MWe	50	100	136	140
Operating output (limited)	MWe	30	75	133	105
Selling price (average)@	$/kw	0.0252	0.030	0.043	0.0364
Boiler life extension	years	25	25	25	25
IR-CFB boiler, aux. equipment and BOP	$/kw	244	182	228	231
Dismantling, erection and commissioning	$/kw	50	45	80	50
EPC cost for IR-CFB repowering (A)	$/kw	294	235	308	281
Capacity factor (assumed)	%	80	80	80	80
Plant downtime period	months	6	6	3	6
Income lost for downtime period (B)+	$/kw	55	47	85	63
Total capital cost (A&B)	$/kw	349	229	393	344
Incremental MW generation income/year	$000's	3523	4476	2428	8928
Aux. fuel and main fuel savings/year	$000's	303	813	*4498	2555
Net annual benefit (C)	$000's	3835	5289	6926	11,483
Payback period (A&B)/(C)	years	4.5	4.3	7.7	4.2

*Apart from IR-CFB repowering, fuel switching from coal to petroleum coke is considered.
@Fuel and limestone operating costs are alone considered.
+Fuel and maintenance costs are not considered.

also compared to PC. This is due to the B&W IR-CFB boiler having significantly less refractory, no high temperature expansion joints and no pulverizers, as well as quick start up which saves auxiliary fuel consumption, and wide turndown range. All of these factors can lead to lower life cycle costs for the power plant.

Technical feasibility studies of four different PC-fired boiler plants have shown the suitability of using B&W's compact IR-CFB boiler for repowering. The studies covered a wide range of domestic fuels for China, India, Ukraine and U.S.A. In each case, re-use of the existing building, support steel with existing foundation, some of the boiler component and balance of plant equipment results in a very attractive capital cost per kilowatt compared to other alternatives.

The advanced design features of B&W's IR-CFB boiler offer a clear advantage for repowering with its compact arrangement as compared with conventional cyclone based CFB technology. These feasibility studies clearly demonstrate that B&W's IR-CFB boiler is capable of fitting into the existing older PC-fired boiler structures from 50 MWe to 140 MWe and repowering can be achieved with low capital cost and attractive payback periods.

References

1. Belin F., Shang Yu J., Levin M. M., Maystrenko Yu A., "Repowering of Ukrainian Power Plants With CFB Boilers," Power-Gen Americas '95, Anaheim, California, U.S.A.

2. Kavidass S., Alexander K. C., "Design consideration of B&W IR-CFB Boilers," Power-Gen Americas '95, Anheim, California, U.S.A., December 5-7, 1995.

3. Kavidass S., "Why CFB is perfect for India," Powerline Magazine, February 1999 issue, India.

217/782-2113

CONSTRUCTION PERMIT - PSD APPROVAL
NSPS-NESHAP EMISSION UNITS

PERMITTEE

Indeck-Elwood LLC
Attn: Mr. James Schneider
600 N. Buffalo Grove Road
Buffalo Grove, Illinois 60089

Application No.: 02030060 I.D. No.: 197035AAJ
Applicant's Designation: Date Received: March 21, 2002
Subject: Electricity Generation Facility
Date Issued: October 10, 2003
Location: Southwest of the Intersection of Drummond and Baseline Roads, Elwood, Will County

Permit is hereby granted to the above-designated Permittee to CONSTRUCT emission source and air pollution control equipment consisting of an electric power plant with two circulating fluidized bed boilers, fuel handling and storage, limestone handling and storage, ash handling and storage, cooling towers, auxiliary gas-fired boiler, and ancillary operations, as described in the above referenced application. This Permit is granted based upon and subject to the findings and conditions that follow.

In conjunction with this permit, approval is given with respect to the federal regulations for Prevention of Significant Deterioration of Air Quality (PSD) for the plant, as described in the application, in that the Illinois Environmental Protection Agency (IEPA) finds that the application fulfills all applicable requirements of 40 CFR 52.21. This approval is issued pursuant to the Clean Air Act, as amended, 42 U.S.C. 7401 et seq., the federal regulations promulgated thereunder at 40 CFR 52.21 for Prevention of Significant Deterioration of Air Quality (PSD), and a Delegation of Authority agreement between the United States Environmental Protection Agency (USEPA) and the Illinois EPA for the administration of the PSD Program. This approval becomes effective in accordance with the provisions of 40 CFR 124.15 and may be appealed in accordance with provisions of 40 CFR 124.19. This approval is based upon the findings that follow. This approval is subject to the following conditions. This approval is also subject to the general requirement that the plant be developed and operated consistent with the specifications and data included in the application and any significant departure from the terms expressed in the application, if not otherwise authorized by this permit, must receive prior written authorization from the Illinois EPA.

If you have any questions on this permit, please call Shashi Shah at 217/782-2113.

Donald E. Sutton, P.E.
Manager, Permit Section
Division of Air Pollution Control

DES:SRS:jar

cc: Region 1
USEPA Region V

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SECTION 1: FINDINGS

1a. Indeck-Elwood LLC (Indeck) has requested a permit for a coal fired power plant with a nominal capacity of 660 MWe gross. The proposed plant would have two identical circulating fluidized bed (CFB) boilers equipped with limestone injection to the bed, selective noncatalytic reduction (SNCR), and a baghouse. Ancillary operations would include coal handling and storage; ash handling and storage; limestone handling and storage; cooling tower; auxiliary boiler, and other ancillary operations.

b. The boilers, which each would have a maximum rated capacity of about 2900 million Btu/hour, would be fired on coal as their primary fuel and petroleum coke and coal tailings as supplemental fuels, with natural gas used as the startup fuel. The boilers would generally be designed for coal mined in Illinois that, prior to being washed, would nominally have 3.51 percent sulfur by weight and 9,965 Btu per pound higher heating value (HHV), which is equivalent to an uncontrolled sulfur dioxide emission rate of 7.0 pounds per million Btu heat input. The washed coal would have an equivalent uncontrolled sulfur dioxide emission rate of approximately 4.7 pounds per million Btu.

2. The plant would be located on an approximately 130-acre site near Elwood in Will County. The site is in an area that is currently designated nonattainment for ozone and attainment for all other criteria pollutants.

3. The proposed plant is a major source under the PSD rules. This is because the CFB boilers, as indicated in the application, would have potential annual emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM), and carbon monoxide (CO) that are each in excess of 100 tons. The plant would also have the potential to emit significant amounts of sulfuric acid mist, fluorides, and beryllium. (Refer to Table I for the potential emissions of the CFB boilers.)

4. The proposed plant is a major source under Illinois’s rules for nonattainment new source review, Major Stationary Sources Construction and Modification (MSSCAM), 35 IAC Part 203. This is because the plant would be located in an area that is designated nonattainment for ozone and, as indicated in the application, would have potential annual emissions of volatile organic materials (VOM) that are in excess of 25 tons. As the plant would be located in an ozone nonattainment, conditions of this construction permit as they relate to emissions of VOM are not considered part of the PSD approval.

5. The proposed plant is a major source for emissions of hazardous air pollutants (HAP). The potential HAP emissions from the plant will be greater than 10 tons of an individual HAP, i.e., hydrogen chloride and hydrogen fluoride. Therefore, the plant is being subjected to review under Section 112(g) of the Clean Air Act.

6. After reviewing the materials submitted by Indeck, the Illinois EPA has determined that the project will (i) comply with applicable Board emission standards (ii) comply with applicable federal emission standards, (iii) utilize Best Available Control Technology (BACT) on emissions of pollutants as required by PSD, (iii) achieve the Lowest Achievable Emission Rate (LAER) for emissions of VOM as required by 35 IAC Part 203, and (v) utilize Maximum Achievable Control Technology (MACT) for emissions of HAP as required by Section 112(g) of the Clean Air Act.

The determinations of BACT, LAER and MACT made by the Illinois EPA for the proposed plant are the control technology determination contained in the permit conditions for specific emission units. For this purpose, limits related to VOM emissions constitute LAER and limits related to hazardous air pollutants emissions constitute

MACT. As limits are not present for specific hazardous air pollutants, the MACT determination relies upon the limits established for other pollutants to also restrict emissions of the hazardous air pollutants for which individual limits are not set. If USEPA were to adopt a MACT regulation that is applicable to the plant that establishes a standard that is more stringent than a standard set as MACT by this permit, the Permittee would be required to comply with such new standard as expeditiously as practicable, with an appropriate compliance date set by the Illinois EPA, pursuant to 40 CFR 63.44(b)(2).

7. The air quality analysis submitted by Indeck and reviewed by the Illinois EPA shows that the proposed project will not cause violations of the ambient air quality standard for NO_x, SO_2, PM/PM_{10}, and CO. The air quality analysis shows compliance with the allowable increment levels established under the PSD regulations.

8. The analysis of alternatives to the project submitted by Indeck shows that the benefits of the proposed plant outweigh the potential impacts of its emissions of VOM, as required by 35 IAC 203.306.

9. The Illinois EPA has determined that the proposed plant complies with all applicable Illinois Pollution Control Board Air Pollution Regulations; the federal Prevention of Significant Deterioration of Air Quality Regulations (PSD), 40 CFR 52.21; applicable federal New Source Performance Standards (NSPS), 40 CFR 60; and Section 112(g) of the Clean Air Act and applicable federal regulations thereunder, National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR 63, Subpart B.

10. In conjunction with the issuance of this construction permit, the Illinois EPA is also issuing an Acid Rain permit for the proposed CFB boilers, to address requirements of the federal Acid Rain program. These CFB boilers would be affected units under the Acid Rain Deposition Control Program pursuant to Title IV of the Clean Air Act. As affected units under the Acid Rain Program, Indeck must hold SO_2 allowances each year for the actual emissions of SO_2 from the CFB boilers. The CFB boilers are also subject to emissions monitoring requirements pursuant to 40 CFR Part 75. As the Acid Rain permit relates to the Acid Rain Program, it is not considered part of the PSD approval.

11. In conjunction with the issuance of this construction permit, the Illinois EPA is also issuing a Budget Permit for the proposed CFB boilers, to address requirements of the federal Acid Rain program and the NO_x Trading Program. As the Budget Permit relates to the NO_x Trading Program, it is not considered part of the PSD approval.

12. A copy of the application, the project summary prepared by the Illinois EPA, a draft of this construction permit, and a draft of the Acid Rain and Budget permits were placed in public locations near the plant, and the public was given notice and an opportunity to examine this material and to participate in a public hearing and to submit comments on these matters.

13. Following consultation with the Illinois Department of Natural Resources, the Illinois EPA has committed to participate in an interagency monitoring program as needed to address concerns related to overall air quality at the Midewin National Tallgrass Prairie (Midewin), as a result of the proposed plant and other development that may occur near the Midewin.

SECTION 2: IDENTIFICATION OF SIGNIFICANT EMISSIONS UNITS

Unit Number	Description	Emission Control Measures
1	Boiler 1 – Circulating Fluidized Bed Boiler	Good Combustion Practices, Limestone Addition to the Bed, Selective Non-Catalytic Reduction, Trimming Scrubber and Baghouse
	Boiler 2 – Circulating Fluidized Bed Boiler (Identical to Boiler 1)	Good Combustion Practices, Limestone Addition to the Bed, Selective Non-Catalytic Reduction, Trimming Scrubber and Baghouse (identical to control for Boiler 1)
2	Bulk Material Handling Operations	Baghouses and Dust Control Measures
3	Cooling Towers	High-Efficiency Drift Eliminators
4	Auxiliary Boiler – Natural Gas Fired Boiler	Low-NO_x Burners
5	Roadways and Other Sources of Fugitive Dust	Paving and Dust Control Measures

SECTION 3: SOURCE-WIDE CONDITIONS

SOURCE-WIDE CONDITION 1: EFFECT OF PERMIT

a. This permit does not relieve the Permittee of the responsibility to comply with all local, state and federal regulations that are part of the applicable Illinois State Implementation Plan, as well as all other applicable federal, state and local requirements.

b. In particular, this permit does not relieve the Permittee from the responsibility to carry out practices during the construction and operation of the plant, such as application of water or dust suppressant sprays to unpaved traffic areas, to minimize fugitive dust and prevent an air pollution nuisance from fugitive dust, as prohibited by 35 IAC 201.141.

SOURCE-WIDE CONDITION 2: VALIDITY OF PERMIT AND COMMENCEMENT OF CONSTRUCTION

a. This permit shall become invalid as applied to the plant and each CFB boiler at the plant if construction is not commenced within 18 months after this permit becomes effective, if construction of a boiler is discontinued for a period of 18 months or more, or if construction of a boiler is not completed within a reasonable period of time, pursuant to 40 CFR 52.21(r)(2) and 40 CFR 63.43(g)(4). This condition supersedes Standard Condition 1.

b. For purposes of the above provisions, the definitions of "construction" and "commence" at 40 CFR 52.21 (b)(8) and (9) shall apply, which requires that a source must enter into a binding agreement for on-site construction or begin actual on-site construction. (See also the definition of "begin actual construction," 40 CFR 52.21 (b)(11)).

SOURCE-WIDE CONDITION 3: EMISSION OFFSETS

a. The Permittee shall maintain 140.4 tons of VOM emission reduction credits generated by other sources in the Chicago ozone nonattainment area such that the total is greater than 1.3 times the VOM emissions allowed from this project.

b. These VOM emission reduction credits are provided by permanent emission reductions as follows. These emission reductions have been relied upon by the Illinois EPA to issue this permit and cannot be used as emission reduction credits for other purposes.

   Minnesota Mining and Manufacturing (3M), Bedford Park, I.D. No. 031012AAR
   Shutdown of Coating Line 6H: 140.4 tons/year

   This reduction has been made federally enforceable by the withdrawal of the air pollution control permits for Coating Line 6H. Accordingly 3M, must obtain a construction permit if it intends to resume operation of the line in the greater Chicago area, in which permit the Illinois EPA will establish restrictions to assure that the line’s actual VOM emissions are permanently reduced by at least 140.4 tons/year.

c. Documentation shall be submitted to the Illinois EPA as follows confirming that the Permittee has obtained the requisite amount of VOM emission offsets as specified above:

i. 3M must submit a letter or other document signed by a responsible official or other authorized agent certifying that a transfer of emission reduction credits from Line 6H at its Bedford Park plant has been made to the Permittee in the requisite amount to provide offsets for this proposed plant.

ii. The Permittee must submit a letter or other document signed by a corporate officer or other authorized agent certifying that a transfer of emission reduction credits has been received from 3M in the requisite amount to provide offsets for this proposed plant. In this letter, the Permittee must also acknowledge that it may subsequently transfer these offsets to another party or return them to 3M only if the preparation for or actual construction of the proposed plant is terminated and this permit expires or is withdrawn, as the Permittee is otherwise under a legal obligation to maintain these offsets pursuant to 35 IAC 203.602.

iii. The above material must be submitted to the Illinois EPA no later than six months after the date that this permit becomes effective.

d. The Permittee may obtain emission reduction credits from an alternate source located in the Chicago ozone nonattainment area, other than 3M, if the following requirements are met:

i. Any proposal for an alternate source of emission reduction credits must be received by the Illinois EPA for review not later three months of the date this permit becomes effective and be accompanied by detailed documentation to support the amount and creditability of the proposed credits.

ii. The alternate source(s) of emission reduction credits must be subject to appropriate measures given the nature of the underlying emission reduction to make the reduction permanent and federally enforceable.

iii. The use of emission reduction credits from the alternate source(s) must be approved by the Illinois EPA. In conjunction with any such approval, the Illinois EPA may and shall revise this permit so that Condition 3(b) appropriately identifies the source(s) of credits.

iv. The Permittee and the alternate source(s) of emission reduction credits must submit to the Illinois EPA, no later than six months after the date that this permit becomes effective, documentation similar in content to that specified by Condition 3(c) to show that transfer of credits has been completed.

e. The Permittee shall not begin actual construction of the proposed plant until applicable requirements with respect to emission offsets, as specified in Condition 3(b) or (c) above, have been satisfied.

Note: This condition represents the actions identified in conjunction with this project to ensure that the project is accompanied by emission offsets and does not interfere with reasonable further progress in reducing VOM emissions in the Chicago ozone nonattainment area. Emission offsets are being required for this project because USEPA has not approved provisions of the Emissions Reduction Market System (ERMS) 35 IAC Part 205, that would allow compliance with the ERMS to satisfy the emission offset requirements in 35 IAC Part 203.

SOURCE-WIDE CONDITION 4: GENERAL PROVISIONS FOR A MAJOR HAP SOURCE

As the plant is a new major source of hazardous air pollutants (HAP) for purposes of Section 112(g) of the Clean Air Act, the Permittee shall comply with all applicable requirements contained in 40 CFR Part 63, Subpart A, pursuant to 40 CFR 63.43(g)(2)(iv).

In particular, for the various emission units at the source, the Permittee shall comply with the following applicable requirements of 40 CFR Part 63 Subpart A, related to startup, shutdown, and malfunction, as defined at 40 CFR 63.2:

a. i. The Permittee shall at all times, including periods of startup, shutdown, and malfunction as defined at 40 CFR 63.2, operate and maintain emission units at the source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions to the levels required by the relevant standards, i.e., meet the emission standard(s) or comply with the applicable Startup, Shutdown, and Malfunction Plan (Plan), as required below. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Illinois EPA and USEPA, which may include, but is not limited to, monitoring results, review of operation and maintenance procedures (including the Plan), review of operation and maintenance records, and inspection of the unit. [40 CFR 63(e)(1)(i)]

ii. The Permittee shall correct malfunctions as soon as practicable after their occurrence in accordance with the applicable Plan. To the extent that an unexpected event arises during a startup, shutdown, or malfunction, the Permittee shall comply by minimizing emissions during such a startup, shutdown, and malfunction event consistent with safety and good air pollution control practices. [40 CFR 63.6(e)(1)(ii)]

iii. These operation and maintenance requirements, which are established pursuant to Section 112 of the Clean Air Act, are enforceable independent of applicable emissions limitations and other applicable requirements. [40 CFR 63(e)(1)(iii)]

b. The Permittee shall develop, implement, and maintain written Startup, Shutdown, and Malfunction Plans (Plans) that describe, in detail, procedures for operating and maintaining the various emission units at the plant during periods of startup, shutdown, and malfunction and a program of corrective action for malfunctioning process, and air pollution control and monitoring equipment used to comply with the relevant emission standards. These Plans shall be developed to satisfy the purposes set forth in 40 CFR 63.6(e)(3)(i)(A), (B) and (C). The Permittee shall develop its initial plans prior to the initial startup of an emission unit(s). [40 CFR 63.6(e)(3)(i)]

i. During periods of startup, shutdown, and malfunction of an emission unit, the Permittee shall operate and maintain such unit, including associated air pollution control and monitoring equipment, in accordance with the procedures specified in the applicable Plan required above. [40CFR 63.6(e)(3)(ii)]

ii. When actions taken by the Permittee during a startup, shutdown, or malfunction (including actions taken to correct a malfunction) are consistent with the procedures specified in the applicable Plan, the Permittee shall keep records for that event which demonstrate that the procedures specified in the Plan were followed. In addition, the Permittee shall keep records of these events as specified in 40 CFR 63.10(b), including records of the occurrence and duration of each startup, shutdown, or malfunction of operation and each malfunction of the air pollution control and monitoring equipment. Furthermore, the Permittee shall confirm in the periodic compliance report that actions taken during periods of startup, shutdown, and malfunction were consistent with the applicable Plan, as required by 40 CFR 63.10(d)(5). [40 CFR 63.6(e)(3)(iii)]

iii. If an action taken by the Permittee during a startup, shutdown, or malfunction (including an action taken to correct a malfunction) of an emission unit is not consistent with the procedures specified in the applicable Plan, and the emission unit exceeds a relevant emission standard, then the Permittee must record the actions taken for that event and must promptly report such actions as specified by 40 CFR 63.63.10(d)(5), unless otherwise specified elsewhere in this permit or in the CAAPP Permit for the plant. [40 CFR 63.6(e)(3)(iv)]

iv. The Permittee shall make changes to the Plan for an emission unit if required by the Illinois EPA or USEPA, as provided for by 40 CFR 63.6(3)(3)(vii), or as otherwise required by 40 CFR 63.6(3)(viii). [40 CFR 63.6(3)(3)(vii) and (viii)]

v. These Plans are records required by this permit, which the Permittee must retain in accordance with the general requirements for retention and availability of records (General Permit Condition 4). In addition, when the Permittee revises a Plan, the Permittee must also retain and make available the previous (i.e., superseded) version of the Plan for a period of at least 5 years after such revision. [40 CFR 63.6(3)(v) and 40 CFR 63.10(b)(1)]

SOURCE-WIDE CONDITION 5: ANCILLARY EQUIPMENT, INCLUDING DIESEL ENGINES

a. Ancillary equipment, including diesel engines, shall be operated in accordance with good air pollution control practice to minimize emissions.

b. i. Diesel engines shall be used to meet the internal electricity or power needs of the plant.

ii. The power output of each diesel engine shall be no more than 1500 horsepower, if it is an emergency or standby unit as defined by 35 IAC 211.1920, or otherwise no more than 500 horsepower.

iii. Fuel fired in diesel engines shall contain no more than 0.05 percent by weight sulfur, so as to qualify as very low sulfur fuel as addressed by the federal Acid Rain program.

SOURCE-WIDE CONDITION 6: AUTHORIZATION TO OPERATE EMISSION UNITS

a. i. Under this permit, each CFB boiler and associated equipment may be operated for a period that ends 180 days after the boiler first generates electricity to allow for equipment shakedown and required emissions testing. This period may be extended by Illinois EPA upon request of the Permittee if additional time is needed to complete shakedown or perform emission testing. This condition supersedes Standard Condition 6.

ii. Upon successful completion of emission testing of a CFB bed boiler demonstrating compliance with applicable limitations, the Permittee may continue to operate the boiler and associated equipment as allowed by Section 39.5(5) of the Environmental Protection Act.

b. i. The remainder of the plant, excluding the CFB boilers, may be operated under this construction permit for a period of 365 days after initial startup of a CFB boiler. This period of time may be extended by the Illinois EPA for up to an additional 365 days upon written request by the Permittee as needed to reasonably accommodate unforeseen difficulties experienced during shakedown of the plant. This condition supersedes Standard Condition 6.

ii. Upon successful completion of emission testing of a CFB boiler demonstrating compliance with applicable limitations, the Permittee may continue to operate the remainder of the plant as allowed by Section 39.5(5) of the Environmental Protection Act.

c. For the CFB boilers and other emission units that are subject to NSPS, the Permittee shall fulfill applicable notification requirements of the NSPS, 40 CFR 60.7(a), including:

i. Written notification of commencement of construction, no later than 30 days after such date (40 CFR 60.7(a)(1)); and

ii. Written notification of the actual date of initial startup, within 15 days after such date (40 CFR 60.7(a)(3)).

<u>SOURCE-WIDE CONDITION 7: AMBIENT ASSESSMENT AND MONITORING</u>

a. The Permittee shall compile information on soil conditions (pH, nutrient levels, trace element content, buffering capacity, etc.) and the condition of vegetation (impact of air pollution and health as indicated by features, rate of growth, etc.) in the Midewin National Tallgrass Prairie (Midewin) as would potentially be affected by pollutants emitted by the proposed plant, as follows:

i. The Permittee shall complete this activity in accordance with a plan that has been submitted to the Illinois Department of Natural Resources (IDNR), the Midewin, and the Illinois EPA for review. As further field data must be collected, the Permittee may contract with qualified experts to collect such data with appropriate oversight by IDNR and the Midewin or work with IDNR and the Midewin to collect such data.

ii. The plan shall be prepared following detailed consultation with IDNR, the Midewin and the Illinois EPA. As part of this consultation with IDNR and the Midewin, the Permittee shall review the existing data available for the area and ongoing data collection efforts. The Permittee shall also solicit recommendations on the scope of further study, including species that should be addressed either as they are threatened or endangered or as they are appropriate indicator species to generally assess the condition of particular ecosystems, the adequacy of the existing data that has been collected in the area for these species, locations for additional sampling sites, the procedures and schedule to be used to collect further data, and the manner in which such data should be collected.

iii. If necessary access to the Midewin can be readily obtained, information shall be compiled for at least ten sites in the vicinity of the plant representing the various ecosystems that are present and four sites in distant locations in the Midewin. These sites shall be selected so as to allow continued collection of representative data at the sites during the operation of the plant.

iv. The compilation of baseline information, representative of the conditions prior to startup of the plant, shall be completed and a comprehensive report submitted prior to the startup of the plant. A subsequent report containing information collected following the startup of the plant shall be prepared and submitted at the same time that the report for optimization of NOx controls required by Unit-Specific Condition 1.16 is required to be submitted. This report shall also include information on the actual operating levels and emissions of the plant during the period over which the soil and vegetation information was collected. Copies of these reports shall be submitted to the IDNR, Midewin, and Illinois EPA

b. The Permittee shall support any monitoring program conducted by the Illinois EPA (or jointly by the Illinois EPA and other governmental bodies) for air emissions impacts in the Midewin, as follows:

   i. Providing the Illinois EPA with any changes in the schedule for construction and startup of the plant, so as to allow baseline monitoring to be conducted for at least a 12-month period prior to initial startup of the plant.

   ii. Assisting in the planning for such monitoring, by reviewing draft monitoring plans, participating in planning meetings and providing comments, as requested.

   iii. Supporting such monitoring, by assisting in identifying suitable sites at which ambient monitoring stations could be located and encouraging the property owners to allow monitoring to be conducted at such sites.

SOURCE-WIDE CONDITION 8: RISK MANAGEMENT PLAN (RMP)

Should this source be subject to the Chemical Accident Prevention Provisions in 40 CFR Part 68, then the Permittee shall submit:

a. A compliance schedule for meeting the requirements of 40 CFR Part 68 by the date provided in 40 CFR 68.10(a); or

b. A certification statement that the source is in compliance with all applicable requirements of 40 CFR Part 68, including the registration and submission of the Risk Management Plan (RMP).

   Note: This condition is imposed pursuant to 40 CFR 68.215(a).

SOURCE-WIDE CONDITION 9: CAPACITY OF PLANT

This permit allows the construction of a power plant that has less capacity than that addressed by the application without obtaining prior approval by the Illinois EPA, as follows. This condition does not affect the Permittee’s obligation to comply with the applicable requirements for the various emission units at the plant:

a. The reduction in the capacity of the plant shall generally act to reduce air quality impacts, as emissions from individual emission units are reduced, heights of structures are reduced, but heights of stacks are not significantly affected.

b. The reduction in the capacity of the plant shall result in a pro-rata reduction in the emission limitations established by this permit for the CFB boilers that are based on the capacity of the boilers.

c. The Permittee shall notify the Illinois EPA prior to proceeding with any significant reduction in the capacity of the plant. In this notification, the Permittee shall describe the proposed change and explain why the proposed change will act to reduce impacts, with detailed supporting documentation.

d. Upon written request by the Illinois EPA, the Permittee shall promptly have dispersion modeling performed to demonstrate that the overall effect of the reduced capacity of the plant is to reduce air quality impacts, so that impacts from the plant remain at or below those predicted by the air quality analysis accompanying the application.

SECTION 4: UNIT-SPECIFIC CONDITIONS FOR PARTICULAR EMISSION UNITS

UNIT-SPECIFIC CONDITION 1: CONDITIONS FOR THE CFB BOILERS

1.1 Emission Unit Description

The affected units for the purpose of these specific permit conditions are two circulating fluidized bed (CFB) boilers with individual air pollution control trains. The boilers are designed to use coal mixed with up to 20 percent petroleum coke and waste coal as their primary fuel. The boilers also have the capability to burn natural gas, which is used for startup of the boilers.

1.2 Control Technology Determination

a. Each boiler shall be operated and maintained with the following features to control emissions.

i. Good combustion practices.

ii. Limestone addition to the bed.

iii. Selective noncatalytic reduction (SNCR).

iv. Trimming scrubber (dry lime scrubber).

v. Fabric filter or “baghouse”.

b. The emissions from each boiler shall not exceed the following limits except during startup, shutdown and malfunction as addressed by Condition 1.2(e). During the shakedown period provided by Source-Wide Condition 5, a boiler is not subject to the SO_2 reduction requirement below and need only comply with the reduction requirement of the NSPS, 40 CFR Part 60, Subpart Da.

i. PM – 0.015 lb/million Btu.

This limit shall apply as a 3-hour block average, with compliance determined by emission testing in accordance with Condition 1.8 and equipment operation.

ii. SO_2 – 0.15 lb/million Btu and, if emissions are 0.10 lb/million Btu or greater, 8 percent of the potential combustion concentration (92 percent reduction) of the solid fuel supply, as received.

These limits shall apply on a 30 day rolling average with compliance determined using the compliance procedures set forth in the NSPS, 40 CFR 60.48a.

iii. NO_x - 0.10 lb/million Btu, or such lower limit as set by the Illinois EPA following the Permittee's evaluation of NO_x emissions and the SNCR system in accordance with Conditions 1.15. For this purpose, the demonstration period for the boiler shall be the first two years of operation.

This limit shall apply on a 30-day rolling average using the compliance procedures of the NSPS, 40 CFR Part 60.48a.

iv. CO - 0.11 lb/million Btu or 321.4 lb/hr*.

This limit shall apply on a 24-hour block average basis, with continuous monitoring conducted in accordance with Condition 1.8.

v. VOM - 0.004 lb/million Btu or 11.7 lb/hr*.

This limit shall apply as a 3-hour block average, with compliance determined by emission testing in accordance with Condition 1.8 and equipment operation.

* This alternative standard is the product of the standard in lb/million Btu and the rated heat input capacity of the boiler.

c. i. The boilers shall each comply with one of the following requirements with respect to emissions of mercury:

A. An emission rate of 0.000002 lb/million Btu or emissions below the detection level of established test methodology (Option A);

B. A removal efficiency of 95 percent achieved without injection of activated carbon or other similar material specifically used to control emissions of mercury, comparing the emissions and the mercury contained in the fuel supply (Option B);

C. Injection of powdered activated carbon or other similar material specifically used to control emissions of mercury in a manner that is designed to achieve the maximum practicable degree of mercury removal (Option C);

D. The requirements for control of mercury emissions established by USEPA pursuant to Section 112(d) of the Clean Air Act (Option D), if such regulations are adopted by USEPA prior to commencement of construction of the affected boiler or if the standard established by such regulations for mercury emissions would be more stringent than one of the above standards. In such case, the Permittee shall promptly notify the Illinois EPA that it intends to comply with the applicable requirements of the adopted regulations and explain the basis on which such election is made.

ii. A. Compliance with Option A or B shall be demonstrated by periodic testing and proper operation of an affected boiler consistent with other applicable requirements that relate to control of mercury (e.g., requirements applicable to particulate matter and SO_2 emissions) as may be further developed or revised in the source's CAAPP Permit. Compliance with Option C shall be demonstrated by proper operation of a boiler and such other measures specified by the applicable construction permit for the injection system.

B. Options A, B and C shall take effect 18 months after initial startup of an affected boiler, provided however, the Permittee may, upon written notice to the Illinois EPA, extend this period for up to an additional 12 months if needed for detailed evaluation of mercury emissions from the boilers or physical changes to the boilers related to control of mercury emissions.

As part of this notice, the Permittee shall explain why the necessary evaluation of emissions or physical changes to the boilers could not reasonably be completed earlier, identify the activities that it intends to perform to evaluate emissions or further enhance control for emissions, and specify the particular practices it will use during this period as good air pollution control practice to minimize emissions of mercury. Prior to the date that Option A, B and C are in effect, the Permittee shall use good air pollution control practices to minimize emissions of mercury.

d. i. The boilers shall each comply with one of the following requirements with respect to emissions of hydrogen chloride:

A. An emission rate of 0.01 lb/million or such lower limit, as low as 0.006 lb/million Btu, as set by the Illinois EPA following the Permittee's evaluation of hydrogen chloride emissions and the acid gas control system, which evaluation shall be submitted with the application for CAAPP permit for the source. This evaluation shall be performed in a manner similar to the evaluation of NO_x emissions required by Condition 1.15. Upon submission of the evaluation and until such time as the Illinois EPA completes its review of the evaluation, a boiler shall comply with the emission limit proposed in the evaluation. (Option A);

B. A removal efficiency of 98 percent, comparing the emissions and the chlorine content of the fuel supply, expressed as equivalent hydrogen chloride (Option B);

C. The requirements for control of hydrogen chloride emissions established by USEPA pursuant to Section 112(d) of the Clean Air Act, once applicable regulations are adopted by USEPA (Option C), if such regulations are adopted by USEPA prior to commencement of construction of the affected boiler or if the standard established by such regulations for hydrogen chloride emissions would be more stringent than one of the above standards. In such case, the Permittee shall promptly notify the Illinois EPA that it intends to comply with the applicable requirements of the adopted regulations and explain the basis on which such election is made.

ii. A. Compliance with Option A and B shall be demonstrated by periodic testing and proper operation of a boiler consistent with other applicable requirements that relate to control of SO_2 emissions, as may be further developed or revised in the source's CAAPP Permit.

B. Option A and B shall take effect 12 months after initial startup of a boiler. Prior to such date, the Permittee shall use good air pollution control practices to minimize emissions of hydrogen chloride.

e. The Permittee shall use reasonable practices to minimize emissions during startup, shutdown and malfunction of a boiler as further addressed in Condition 1.6, including the following:

i. Use of natural gas, during startup to heat the boiler prior to initiating firing of solid fuel;

ii. Operation of the boiler and associated air pollution control equipment in accordance with written operating procedures that include startup, shutdown and malfunction plan(s); and

iii. Inspection, maintenance and repair of the boiler and associated air pollution control equipment in accordance with written maintenance procedures.

1.3 Applicable Federal Emission Standards

a. i. The boilers are subject to a New Source Performance Standard (NSPS) for Electric Utility Steam Generating Units, 40 CFR 60, Subparts A and Da. The Illinois EPA administers NSPS in Illinois on behalf of the USEPA under a delegation agreement.

ii. The emissions from each boiler shall not exceed the applicable limits pursuant to the NSPS. In particular, the NO_x emissions from each boiler shall not exceed 1.6 lb/MW-hr gross energy output, based on a 30-day rolling average, pursuant to 40 CFR 60.44a(d).

iii. The particulate matter emissions from each boiler shall not exceed 20 percent opacity (6-minute average), except for one 6- minute period per hour of not more than 27 percent opacity pursuant to 40 CFR 60.42a(b).

b. At all times, the Permittee shall maintain and operate each boiler, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions, pursuant to 40 CFR 60.11(d).

1.4 Applicable State Emission Standards

Each boiler is subject to the following state emission standards.

a. Opacity – 35 IAC 212.122 (20 percent opacity, except as allowed by 35 IAC 212.122(b))*

b. Particulate Matter – 35 IAC 212.201 (0.1 lb/million Btu)**

c. Sulfur Dioxide – 35 IAC 214.121 (1.2 lb/million Btu)**

d. Carbon Monoxide – 35 IAC 216.121 (200 ppm, @ 50 % excess air)**

e. Nitrogen Oxides – 35 IAC 217.121 (0.7 lb/million Btu)**

* This standard is not as stringent as Condition 1.3(a)(iii).

** This standard is not as stringent as Condition 1.2.

1.5. Applicability of Other Regulations

a. Each boiler is an affected unit under the federal Acid Rain Deposition Control Program pursuant to Title IV of the Clean Air Act and is subject to certain control requirements and emissions monitoring requirements pursuant to 40 CFR Parts 72, 73 and 75. (See also Trading Program Condition 1, (Section 5, Condition 1).

b. The boilers would qualify as Electrical Generating Units (EGU) for purposes of 35 IAC Part 217, Subpart W, the NO_x Trading Program for Electrical Generating Units. As EGU, the Permittee would have to hold NO_x allowances for the NO_x emissions of the boilers during each seasonal control period. (See also Trading Program Condition 3 (Section 5, Condition 3).

c. For particulate matter, the boilers are pollutant-specific emissions units that will be subject to 40 CFR Part 64, Compliance Assurance Monitoring for Major Stationary Sources. As such, the application for Clean Air Act Permit Program (CAAPP) Permit for the source must include a Compliance Assurance Monitoring (CAM) plan for the boilers.

1.6 Operating Requirements

a. The Permittee shall operate each boiler and associated air pollution control equipment in accordance with good air pollution control practice to minimize emissions, by operating in accordance with detailed written operating procedures as it is safe to do so, which procedures at a minimum shall:

i. Address startup, normal operation, and shutdown and malfunction events and provide for review of relevant operating parameters of the boiler systems during startup, shutdown and malfunction as necessary to make adjustments to reduce or eliminate any excess emissions.

ii. With respect to startup, address readily foreseeable startup scenarios, including so called "hot startups" when the operation of a boiler is only temporarily interrupted and provide for appropriate operating review of the operational condition of a boiler prior to initiating startup of the boiler.

iii. With respect to malfunction, identify and address likely malfunction events with specific programs of corrective actions and provide that upon occurrence of a malfunction that will result in emissions in excess of the applicable limits in Condition 1.2, the Permittee shall, as soon as practicable, repair the affected equipment, reduce the operating rate of the boiler or remove the boiler from service so that excess emissions cease.

Consistent with the above, if the Permittee has maintained and operated a boiler and associated air pollution control equipment so that malfunctions are infrequent, sudden, not caused by poor maintenance or careless operation, and in general are not reasonably preventable, the Permittee shall begin shutdown of the boiler within 90 minutes, unless the malfunction is expected to be repaired within 120 minutes or such shutdown could threaten the stability of the regional electrical power supply. In such case, shutdown of the system shall be undertaken when it is apparent that repair will not be accomplished within 120 minutes or shutdown will not endanger the regional power system. In no case shall shutdown of the boiler be delayed solely for the economic benefit of the Permittee.

Note: If the Permittee determines that the continuous emission monitoring system (CEMS) is inaccurately reporting excess emissions, the boiler may continue to operate provided the Permittee records the information it is relying upon to conclude that the boiler and associated emission control systems are functioning properly and the CEMS is reporting inaccurate data and the Permittee takes prompt action to resolve the accuracy of the CEMS.

b. The Permittee shall maintain each boiler and associated air pollution control equipment in accordance with good air pollution control practice to assure proper functioning of equipment and minimize malfunctions, including maintaining the boiler in accordance with written procedures developed for this purpose.

c. The Permittee shall handle the fuel for the boilers in accordance with a written Fuel Management Plan that shall be designed to provide the boilers with a consistent fuel supply that meets relevant criteria needed for proper operation of the boilers and their control systems.

d. The Permittee shall review its operating and maintenance procedures and its fuel management plan for the boilers as required above on a regular basis and revise them if needed consistent with good air pollution control practice based on actual operating experience and equipment performance. This review shall occur at least annually if not otherwise initiated by occurrence of a startup, shakedown, or malfunction event that is not adequately addressed by the existing plans or a specific request by the Illinois EPA for such review.

1.7 Emission Limitations

Emissions from the boilers shall not exceed the limits in Table I. The limits in Table I are based upon the emission rates and the maximum firing rate specified in the permit application consistent with the air quality analysis submitted by the Permittee to comply with PSD. Compliance with hourly limits shall be determined with testing and monitoring as required by Conditions 1.8 and 1.9 and proper equipment operation in accordance with Condition 1.6.

1.8 Emission Testing

a. i. A. Within 60 days after achieving the maximum production rate at which an affected boiler will be operated but not later than 180 days after initial startup of each boiler, the Permittee shall have tests conducted for opacity and emissions of NO_x, CO, PM, VOM, SO_2, hydrogen chloride, hydrogen fluoride, sulfuric acid mist, and mercury and other metals as follows at its expense by an approved testing service while the boiler is operating at maximum operating load and other representative operating conditions, including firing of coal only and coal with supplemental fuel. (In addition, the Permittee may also perform measurements to evaluate emissions at other load and operating conditions.)

B. This period of time may be extended by the Illinois EPA for up to an additional 365 days upon written request by the Permittee as needed to reasonably accommodate unforeseen difficulties in the startup and testing of the boiler, provided that initial performance testing required by the NSPS, 40 CFR Part 60, Subpart Da has been completed for the boiler and the test report submitted to the Illinois EPA.

ii. Between 9 and 15 months after performance of the initial testing that demonstrates compliance with applicable requirements, the Permittee shall have the emissions of PM, VOM, hydrogen chloride, hydrogen fluoride, sulfuric acid mist, and mercury and other metals from each affected boiler retested as specified above.

iii. A. Thereafter, the Permittee shall have PM emissions from each affected boiler tested at a regular interval. This interval shall be no greater than 36 months, unless the results of two consecutive PM tests for a boiler demonstrate PM emissions of 0.010 lb/million Btu or less, in which case the interval between tests shall be no greater than 72 months. However, if a PM test for a boiler then shows PM emissions above 0.010 lb/million Btu, the maximum interval between testing shall revert to 36 months until two consecutive tests again show PM emissions of 0.010 lb/million Btu or less. For the purposes of these provisions, the two consecutive tests must be at least 24 months apart.

B. Whenever PM testing for a boiler is performed as required above, testing for emissions of mercury and hydrogen chloride shall also be performed as provided below.

iv. In addition to the emission testing required above, the Permittee shall have emission tests conducted as requested by the Illinois EPA for a boiler within 45 days of a written request by the Illinois EPA or such later date agreed to by the Illinois EPA. Among other reasons, such testing may be required if there is a significant increase in the mercury or chlorine content of the fuel supply to the boilers.

Note: Specific requirements for periodic emission testing may be established in the CAAPP Permit for the plant.

v. Within two years of the initial startup of each affected boiler, the Permittee shall have emission testing conducted for dioxin/furan emissions.

b. The following methods and procedures shall be used for testing, unless otherwise specified or approved by the Illinois EPA.

Location of Sample Points	Method 1
Gas Flow and Velocity	Method 2
Flue Gas Weight	Method 3 or 3A
Moisture	Method 4
Particulate Matter[1]	Method 5, as specified by 40 CFR 60.48a(b), and Method 201 or 201A (40 CFR 51, Appendix M)
Condensable Particulate	Method 202
Opacity[2]	Method 9, as specified by 40 CFR 60.48a(b)(3)
Nitrogen Oxides[2]	Method 19, as specified by 40 CFR 60.48a(d)
Sulfur Dioxides[2]	Method 19, as specified by 40 CFR 60.48a(c)
Carbon Monoxide[2]	Method 10
Volatile Organic Material[3]	Method 18 or 25A
Sulfuric Acid Mist	Method 8
Hydrogen Chloride	Method 26
Hydrogen Fluoride	Method 26
Metals [4, 5]	Method 29
Dioxin/Furan	Method 23

Notes:

1. The Permittee may report all PM emissions measured by USEPA Method 5 as PM_{10}, in which case separate testing using USEPA Method 201 or 201A need not be performed.

2. Emission testing shall be conducted for purposes of certification of the continuous emission monitors required by Condition 1.9. Thereafter, the NO_x, SO_2 and CO emission data from certified monitors may be provided in lieu of conducting emissions tests.

3. The Permittee may exclude methane, ethane and other exempt compounds from the results of any VOM test provided that the test protocol to quantify and correct for any such compounds is included in the test plan approved by the Illinois EPA.

4. For purposes of this permit, metals are defined as mercury, arsenic, beryllium, cadmium, chromium, lead, manganese, and nickel.

5. During the initial emissions testing for metals, the Permittee shall also conduct measurements using established test methods for the principle forms of mercury present in the emissions, i.e., particle bound mercury, oxidized mercury and elemental mercury.

c. i. Test plans, test notifications, and test reports shall be submitted to the Illinois EPA in accordance with the General Condition 2 (Section 6, Conditions 2)

ii. In addition to other information required in a test report, test reports shall include detailed information on the operating conditions of a boiler during testing, including:

A. Fuel consumption (in tons);

B. Composition of fuel (Refer to Condition 1.10(b)), including the metals, chlorine and fluorine content, expressed in pound per million Btu;

C. Firing rate (million Btu/hr) and other significant operating parameters of the boiler, including temperature in the boiler in the area before the SNCR system;

D. Control device operating rates, e.g., limestone addition rate, SNCR reagent injection rate, injection rate of trimming scrubber, baghouse pressure drop, etc.;

E. Opacity of the exhaust from the boiler, 6-minute averages and 1-hour averages;

F. Turbine/Generator output rate (MWe).

1.9 Emission Monitoring

a. i. The Permittee shall install, certify, operate, calibrate, and maintain continuous monitoring systems on each boiler for opacity, emissions of SO_2, NO_x and CO, and either oxygen or carbon dioxide in the exhaust.

ii. The Permittee shall fulfill the applicable requirements for monitoring in the NSPS (40 CFR 60.13, 60.47a, and 40 CFR 60 Appendix B), the federal Acid Rain Program (40 CFR Part 75), the NO_x Trading Program for Electrical Generating Units (35 IAC Part 217, Subpart W) and NESHAP (40 CFR 63.8 and 63.10). These rules require that the Permittee maintain detailed records for both the measurements made by these systems and the maintenance, calibration and operational activity associated with the monitoring systems.

iii. The Permittee shall also operate and maintain these monitoring systems according to site-specific monitoring plan(s), which shall be submitted at least 60 days before the initial startup of a boiler to the Illinois EPA for its review and approval. With this submission, the Permittee shall submit the proposed type of monitoring equipment and proposed sampling location(s), which shall be approved by the Illinois EPA prior to installation of equipment.

b. In addition, when NO_x or SO_2 emission data are not obtained from a continuous monitoring system because of system breakdowns, repairs, calibration checks and zero span adjustments, emission data shall be obtained by using standby monitoring systems, emission testing using USEPA Reference Methods (Method 7 or 7A for NO_x and Method 6 for SO_2), or other approved methods as necessary to provide emission data for a minimum of 75 percent of the operating hours in a boiler operating day, in at least 22 out of 30 successive boiler operating days, pursuant to 40 CFR 60.47a(f) and (h).

Note: Fulfillment of the above criteria for availability of emission data from a monitoring system does not shield the Permittee from potential enforcement for failure to properly maintain and operate the system.

1.10. Operational Monitoring and Measurements

a. The Permittee shall install, evaluate, operate, and maintain meters to measure and record consumption of natural gas by each boiler.

b. i. A. The Permittee shall sample and analyze the sulfur and heat content of the fuel supplied to the boilers in accordance with USEPA Reference Method 19 (40 CFR 60, Appendix A, Method 19).

B. This sampling and analysis shall include separate measurements for the sulfur and heat content of the fuels supplied to the boilers.

ii. The Permittee shall analyze samples of all coal supplies and any alternate fuel supplies that are components in the solid fuel supply to the boilers and the solid fuel supply itself for mercury and other metals, chlorine and fluorine content, as follows:

A. Analysis shall be conducted in accordance with USEPA Reference Methods or other method approved by USEPA.

B. Analysis of the fuel supply to the boiler itself shall be conducted in conjunction with performance testing of a boiler.

C. Analysis of representative samples of solid fuels shall be conducted in conjunction with acceptance of fuel from a new coal mine or an alternate fuel.

D. Analysis of representative samples of solid fuels shall be conducted at least every two years, if a more frequent analysis is not needed pursuant to the above requirements.

E. The CAAPP permit may revise or relax these requirements.

c. i. The Permittee shall install, operate and maintain systems to measure key operating parameters of the control equipment and control measures for each boiler, including:

A. Limestone addition rate to the bed;

B. Temperature in the boiler in the area before the SNCR system;

C. Reagent injection rate for the SNCR unit;

D. Sorbent injection rate for the trimming scrubber;

E. Pressure drop across the baghouse.

ii. The Permittee shall maintain the records of the measurements made by these systems and records of maintenance and operational activity associated with the systems.

d. If a Performance Specification for particulate matter continuous monitoring systems is adopted by USEPA more than 6 months before the scheduled date for initial start-up of the first boiler, the Permittee shall install and operate such a system on each boiler for the purpose of compliance assurance monitoring. The Permittee shall operate, calibrate and maintain each such system in accordance with the applicable USEPA performance specification and other applicable requirements of the NSPS for monitoring systems and in a manner that is generally consistent with published USEPA guidance for use such systems for compliance assurance monitoring, e.g., *Fabric Filter Bag Leak Detection Guidance*, EPA-454/R-98-015, September 1997. The Permittee shall also operate and maintain these monitoring systems according to a site-specific monitoring plan, which shall be submitted at least 60 days before the initial startup of a boiler to the Illinois EPA for its review and approval. With this submission, the Permittee shall submit the proposed type of monitoring equipment and proposed sampling location, which shall be approved by the Illinois EPA prior to installation of equipment.

1.11. Recordkeeping

a. The Permittee shall maintain the following records with respect to operation and maintenance of each boiler and associated control equipment:

i. An operating log for the boiler that at a minimum shall address:

A. Each startup of the boiler, including the nature of the startup, sequence and timing of major steps in the startup, any unusual occurrences during the startup, and any deviations from the established startup procedures, with explanation;

B. Each shutdown of the boiler including the nature and reason for the shutdown, sequence and timing of major steps in the shutdown, any unusual occurrences during the shutdown, and any deviations from the established shutdown procedures, with explanation; and

C. Each malfunction of the boiler system that significantly impairs emission performance, including the nature and duration of the event, sequence and timing of major steps in the malfunction, corrective actions taken, any deviations from the established procedures for such a malfunction, and preventative actions taken to address similar events.

ii. Inspection, maintenance and repair log(s) for the boiler system that at a minimum shall identify such activities that are performed as related to components that may effect emissions; the reason for such activities, i.e., whether planned or initiated due to a specific event or condition, and any failure to carry out the established maintenance procedures, with explanation.

iii. Copies of the steam charts and daily records of steam and electricity generation.

b. The Permittee shall maintain records of the following items related to fuels used in the boilers:

i. Records of the sampling and analysis of solid fuel supply to the boilers conducted in accordance with Condition 1.10(b).

ii. A. The sulfur content of solid fuel, lb sulfur/million Btu, supplied to each boiler, as determined pursuant to Condition 1.10(b)(i); and

B. The sulfur content of solid fuel supplied to the boiler on a 30-day rolling average, determined from the above data.

iii. The amount of fuel combusted in each boiler by type of fuel as specified in 40 CFR Part 60, Appendix A, Method 19.

c. For each boiler, the Permittee shall maintain records of the following items related to emissions:

i. Records of SO_2 NO_x and PM emissions and operation for each boiler operating day, as specified by 40 CFR 60.49a.

ii. With respect to the SO_2 reduction based limit in Condition 1.2(b)(ii) and 1.3, for each 30 day averaging period, the SO_2 emissions in lb/million Btu and the required SO_2 emission rate as determined by applying the permissible emission fraction to the potential SO_2 emission rate of the solid fuel supply.

iii. Records of CO emissions of the boiler based on the continuous emissions monitoring system required by Condition 1.9.

iv. Records of emissions of VOM, mercury and other pollutants from the boiler, based on fuel usage and other operating data for the boiler and appropriate emission factors, with supporting documentation.

d. The Permittee shall record the following information for any period during which a boiler deviated from applicable requirements:

i. Each period when the operating parameters of the baghouse, such as pressure drop, as measured pursuant to Condition 1.10, deviated outside the levels set as good air pollution control practice (date, duration and description of the event).

ii. Each period when a baghouse failed to operate properly, which records shall include at least the information specified by General Condition 3 (Section 6, Condition 3).

iii. Each period during which an affected unit exceeded the requirements of this permit, including applicable emission limits, which records shall include at least the information specified by General Condition 3 (Section 6, Condition 3).

1.12. Notifications

a. The Permittee shall notify the Illinois EPA within 30 days of deviations from applicable requirements that are not addressed by the regular reporting required below. These notifications shall include the information specified by General Condition 4 (Section 6, Condition 4).

b. The Permittee shall notify the Illinois EPA in writing at least 30 days prior to initial firing of any solid fuel other than coal, petroleum coke or coal tailings in a boiler.

1.13. Reporting

a. i. The Permittee shall fulfill applicable reporting requirements in the NSPS, 40 CFR 60.7(c) and 60.49a, for each boiler. For this purpose, quarterly reports shall be submitted no later than 30 days after the end of each calendar quarter. (40 CFR 60.49a (i))

ii. In lieu of submittal of paper reports, the Permittee may submit electronic quarterly reports for SO_2, NO_x or opacity. The electronic reports shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement indicating whether compliance with applicable emission standards and minimum data requirements of 40 CFR 60.49a were achieved during the reporting period. (40 CFR 60.49a(j))

b. i. Either as part of the periodic NSPS report or accompanying such report, the Permittee shall report to the Illinois EPA any and all opacity and emission measurements for a boiler that are in excess of the respective requirements set by this permit. These reports shall provide for each such incident, the pollutant emission rate, the date and duration of the incident, and whether it occurred during startup, malfunction, breakdown, or shutdown. If an incident occurred during malfunction or breakdown, the corrective actions and actions taken to prevent or minimize future reoccurrences shall also be reported.

ii. These reports shall also address any deviations from applicable compliance procedures for a boiler established by this permit, including specifying periods during which the continuous monitoring systems were not in operation.

c. The Permittee shall comply with applicable reporting requirements under the Acid Rain Program, with a single copy of such report sent to Illinois EPA, Bureau of Air, Compliance and Enforcement Section.

1.14 Operational Flexibility/Anticipated Operating Scenarios

a. The Permittee is authorized to use fuel from different suppliers in the boilers without prior notification to the Illinois EPA or revision of this permit.

b. This condition does not affect the Permittee's obligation to continue to comply with applicable requirements or to properly obtain a construction permit in a timely manner for any activity involving the boiler or the fuel handling equipment that constitutes construction or modification of an emission unit, as defined in 35 IAC 201.102.

1.15 Optimization of Control of NO_x Emissions

a. i. The Permittee shall evaluate NO_x emissions from boilers to determine whether a lower NO_x emission limit (as low as 0.08 lb/million Btu) may be reliably achieved while complying with other emission limits and without significant risk to equipment or personnel. This evaluation shall also examine whether there will be significant increase in ammonia-related emissions from the boilers, as well as unreasonable increase in maintenance and repair needed for the boilers.

ii. This permit will be revised to set lower emission limit(s) for NO_x emissions (but no lower than 0.08 lb/million Btu) if as a result of this evaluation the Illinois EPA finds that the boilers can consistently comply with such limit(s). Additional parameters or factors, e.g., the nitrogen content of the fuel supply, may be included in such limits to address particular modes of operation during which particular emission limits may or may not be achievable.

iii. If the Permittee fails to complete the evaluation or submit the required report in a timely manner, the NO_x emission limit shall automatically revert to 0.08 lb NO_x per million Btu

b. The Permittee shall perform this evaluation of NO_x emissions in accordance with a plan submitted to the Illinois EPA for review and comment. The initial plan shall be submitted to the Illinois EPA no later than 90 days after initial start-up of a boiler.

c. The plan shall provide for systematic evaluation of changes, within the normal or feasible range of operation, in the following elements as related to the monitored NO_x emissions:

i. Boiler operating load and operating settings;

ii. Operating rate and settings of the SNCR system;

iii. Flue gas temperature at SNCR injection point(s);

iv. Combustion settings, including excess oxygen;

v. Limestone and sorbent usage rates;

vi. Nitrogen content of the fuel supply;

vii. Particulate matter and operating parameters for baghouses;

viii. Opacity, particulate matter and sulfuric acid mist emissions; and

ix. Ammonia slip (emissions of ammonia and secondary ammonia compounds).

d. The Permittee shall promptly begin this evaluation after a boiler demonstrates compliance with the applicable emission limits as shown by emission testing and monitoring. At this time, the Permittee shall submit an update to the plan that describes its findings with respect to control of NO_x emissions during the shakedown of the boilers, which highlights possible areas of concern for the evaluation.

e. i. This evaluation shall be completed and a detailed written report submitted to the Illinois EPA within two years after the initial startup of a boiler. This report shall include proposed alternative limit(s) for NO_x emissions.

ii. This deadline may be extended for an additional year if the Permittee submits an interim report demonstrating the need for additional time to effectively evaluate NO_x emissions or to coordinate this evaluation with the ambient assessment required by Source-Wide Condition 7.

1.16 Construction of Additional Control Measures

The Permittee is generally authorized under this permit to construct and operate additional devices and features to control emissions from a boiler, which are not described in the application for this permit, as follows. This condition does not affect the Permittee's obligation to comply with the applicable requirements for the boilers:

a. This authorization only extends to devices or features that are designed to reduce emissions, such as the addition of adsorbent materials other than limestone to the boiler bed and ductwork injection of sorbent materials other than lime or wet scrubbing prior to the baghouse. These measures may also serve to improve boiler operation as they reduce consumption of materials but do not include measures that would increase a boiler's rated heat input capacity.

b. This authorization only extends to additional devices or features that are identified during the detailed design of the boilers and any refinements to that design that occur during construction and the initial operation of the boilers.

c. Prior to beginning actual construction of any new control device, the Permittee shall apply for and obtain a separate construction permit for it from the Illinois EPA pursuant to 35 IAC Part 201, Subpart D. In the application for this permit, the Permittee shall describe the additional device and explain how it will act to reduce emissions, with detailed supporting documentation. In acting upon this permit, the Illinois EPA may specify additional operating parameters that must be monitored or measured, such as pressure drop across the scrubber, and additional provisions for required emissions testing.

d. Upon written request by the Illinois EPA, the Permittee shall promptly have dispersion modeling performed to demonstrate that the proposed device or feature for which a construction permit would be required does not significantly effect the air quality impacts from the boilers, so that impacts from the boilers are of the same magnitude of those predicted by the air quality analysis accompanying the application.

UNIT-SPECIFIC CONDITION 2: CONDITIONS FOR BULK MATERIAL HANDLING OPERATIONS

2.1 Description of Emission Units

The affected units for the purpose of these unit-specific permit conditions are operations that handle materials in bulk that are involved with the operation of the power plant and have the potential for particulate matter emissions, including coal, petroleum coke, coal tailings, limestone, and ash. Affected units include receiving, transfer, handling, storage, processing or preparation (drying, crushing, etc.) and loading operations for such materials.

2.2 Control Technology Determination

a. i. Emissions of particulate matter from affected units, other than operations associated with material storage in building or associated with storage piles, shall be controlled with enclosures and aspiration to baghouses or other filtration devices designed to emit no more than 0.005 grains/dry standard cubic foot (gr/dscf). These devices shall be operated in accordance with good air pollution control practice to minimize emissions.

ii. There shall be no visible fugitive emissions, as defined by 40 CFR 60.671, from storage buildings.

iii. Storage piles shall be controlled by enclosure, material quality, temporary covers and application of water or other dust suppressants so as to minimize fugitive emissions to the extent practicable.

b. i. The only fuel burned in the limestone drying mills shall be natural gas, as defined by 40 CFR 60.41a.

ii. Emissions from each limestone drying mill attributable to combustion of fuel shall not exceed the following limits, except during startup and shutdown. These limits shall apply as a 3-hour block average, with compliance determined in accordance with Condition 2.8 and proper operation.

A. NO_x – 0.073 lb/million Btu.

B. CO – 0.20 lb/million Btu.

C. VOM – 0.02 lb/million Btu.

2.3 Applicable Federal Emission Standards

a. Affected units engaged in handling limestone shall comply with applicable requirements of the NSPS for Nonmetallic Mineral Processing Plants, 40 CFR 60, Subpart OOO and related provisions of 40 CFR 60, Subpart A.

i. Pursuant to the NSPS, stack emissions of particulate matter are subject to the following limitations:

A. The rate of emissions shall not exceed 0.05 gram/dscm (0.02 g/dscf) (40 CFR 60.672(a)(1))*

B. The opacity of emissions shall not exceed 7 percent. (40 CFR 60.672(a)(2))

ii. Pursuant to the NSPS, fugitive emissions of particulate matter are subject to the following limitations:

A. The opacity of emissions from grinding mills, screens (except truck dumping), storage bins, and enclosed truck or railcar loading operations shall not exceed 10 percent. (40 CFR 60.672(b) and (d))*

B. The opacity of emissions from crushers shall not exceed 10 percent. (40 CFR 60.672(c))*

C. Truck dumping into any screening operation, feed hopper, or crusher is exempt from the above standards. (40 CFR 60.672(d))*

b. Affected units engaged in handling coal shall comply with applicable requirements of the NSPS for Coal Preparation Plants, 40 CFR 60, Subpart Y, and related provisions of 40 CFR 60, Subpart A. Note: These NSPS are applicable because coal will be processed at the plant by crushing.

Pursuant to the NSPS, the opacity of the exhaust from coal processing and conveying equipment, coal storage systems (other than open storage piles), and coal loading systems shall not exceed 20 percent.*

* Condition 2.2(a) establishes a more stringent requirement than this standard.

c. At all times, the Permittee shall maintain and operate affected units that are subject to NSPS, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions, pursuant to 40 CFR 60.11(d).

d. This permit reflects a determination by the Illinois EPA that the NSPS for Calciners and Dryers in Mineral Industries, 40 CFR 60 Subpart UUU, does not apply to the limestone drying systems because processing of limestone is not addressed by these standards.

2.4 Applicable State Emission Standards

a. The emission of smoke or other particulate matter from affected units shall not have an opacity greater than 30 percent, except as allowed by 35 IAC 212.124. Compliance with this limit shall be determined by 6-minute averages of opacity measurements in accordance with USEPA Reference Method 9. [35 IAC 212.109 and 212.123(a)]

b. With respect to emissions of fugitive particulate matter, affected units shall comply with 35 IAC 212.301, which provides that visible emissions of fugitive particulate matter shall not be visible from any process, including any material handling or storage activity, when looking generally toward the zenith at a point beyond the property line of the source, except as provided by 35 IAC 212.314.

c. Affected units shall comply with applicable emission standards for fugitive particulate matter, as follow, which generally apply to the source because it is located in Channahon Township, Will County.

i. Crushers, grinding mills, screening operations, conveyor transfer points, conveyors, bagging operations, storage bins, and fine product truck and railcar loading operations shall be sprayed with water or a surfactant solution, utilize choke-feeding, or be treated by an equivalent method of emission control [35 IAC 212.308]

ii. All unloading and transportation of materials collected by pollution control equipment shall be enclosed or shall utilize spraying, pelletizing, screw conveying or other equivalent methods [35 IAC 212.307].

2.5 Applicability of Other Regulations

a. This permit is issued based on the outdoor storage piles at the plant not meeting the applicability thresholds of 35 IAC 212.304, so that the provisions of 35 IAC 212.304, 212.305, and 212.306 are not applicable.

b. This permit is issued based on affected units readily complying with the applicable particulate matter emission limit pursuant to 35 IAC 212.321, which rule limits emissions based on the process weight rate of an unit and allows a minimum emission rate emission of 0.55 lb/hour for any unit.

2.6 Operating Requirements

a. i. The plant shall be designed and operated to store bulk materials that have the potential for particulate matter emissions in silos, bins, and buildings, without storage of such material in outdoor piles except on a temporary basis during breakdown or other disruption in the capabilities of the enclosed storage facilities.

ii. The plant shall be designed and operated with enclosed conveyors for transfer of coal and limestone from the material storage facility to the boiler facility, and these materials shall only be transferred by truck on a temporary basis during breakdown of the conveyor system.

b. i. The Permittee shall carry out control of fugitive particulate matter emissions from affected units in accordance with a written operating program describing the measures being implemented in accordance with Conditions 2.2 and 2.4 to control emissions at each area of the plant with the potential to generate significant quantities of such emissions, which program shall be kept current.

A. This program shall include maps or diagrams indicating the location of affected units with the potential for fugitive emissions, accompanied the following information for each such unit: a general description of the unit, its size (area or volume), the expected level of activity, the nature and extent of enclosure, and a description of installed air pollution control equipment.

B. This program shall include a detailed description of any additional emission control technique (e.g., water or surfactant spray) including: typical flow of water and additive concentration; rate or normal frequency at which measures would be implemented; circumstances in which the measure would not be implemented e.g., adequate surface moisture on material; triggers for additional control, e.g. observation of 10 percent opacity; and calculated control efficiency.

C. This program shall also meet any further requirements of 35 IAC 212.309 and 212.310 for affected units subject to 35 IAC 212.307 or 212.308 (Condition 2.4).

ii. The Permittee shall submit copies of this operating program to the Illinois EPA for review as follows:

A. A program for the construction of the plant shall be submitted with 30 days of beginning actual construction of the plant.

B. The initial operating program for plant shall be submitted within 90 days of initial start up of the plant.

C. Significant amendments to the program by the Permittee shall be submitted within 30 days.

iii. A revised operating program shall be submitted to the Illinois EPA for review within 90 days of a request from the Illinois EPA for revision to address observed deficiencies in control of fugitive emissions.

c. The Permittee shall conduct inspections of affected units on at least a monthly basis to verify that the measures identified in the operating program and other measures required to control emissions from affected units are being properly implemented. When the plant begins to handle bulk materials in the affected units, these inspections shall include observation of buildings and structures in which affected units are located for the occurrence of visible emissions.

d. i. This permit does not authorize operation of the affected units for purposes that are unrelated to the operation of the power plant, such as receiving and storing coal that is then shipped to another source.

ii. A. The only fuel used for affected units shall be natural gas.

B. The rated heat input capacity of affected units shall not exceed 36 million Btu/hour, total.

2.7 Emission Limitations

Emissions from affected units shall not exceed the limitations in Table II and III and the limitations specified in the records required by Condition 2.11(a).

2.8 Emission Testing

a. i. A. Within 60 days after achieving the maximum production rate at which a limestone drying mill or other affected emission unit subject to NSPS will be operated but not later than 180 days after initial startup of each such unit, the Permittee shall have emissions tests conducted as follows for such unit below by an approved testing service at its expense under conditions that are representative of maximum emissions.

B. This period of time may be extended by the Illinois EPA upon written request by the Permittee as needed to reasonably accommodate unforeseen difficulties in the startup and testing of an affected unit, provided that initial emissions testing required by the NSPS has been completed for the unit and the test report submitted to the Illinois EPA.

ii. In addition to the initial emission testing required above, the Permittee shall perform emission tests as requested by the Illinois EPA for an affected unit within 45 days of a written request by the Illinois EPA or such later date agreed to by the Illinois EPA.

b. The following methods and procedures shall be used for emission testing

i. The following USEPA methods and procedures shall be used for particulate matter and opacity measurements for the affected units subject to 40 CFR Part 60, Subpart OOO, as specified in 40 CFR 60.675:

Particulate Matter	Method 5 or 17
Opacity	Method 9

ii. The following USEPA methods and procedures shall be used for particulate matter and opacity measurements for the affected units subject to 40 CFR 60, Subpart Y, as specified in 40 CFR 60.254:

Particulate Matter - Method 5, the sampling time and sample volume for each run shall be at least 60 minutes and 30 dscf. Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin.

Opacity - Method 9, opacity measurements shall be performed by a certified observer.

iii. The following USEPA methods and procedures shall be used for testing the combustion emissions of one randomly selected limestone mill:

Nitrogen Oxides	Method 19
Carbon Monoxide	Method 10
Volatile Organic Material	Method ~~18 or~~ 25A and 18

c. Test plan(s), test notifications, and test reports shall be submitted to the Illinois EPA in accordance with General Condition 2. (Section 6, Condition 2)

2.9 Emission Monitoring

None

2.10 Operational Monitoring and Measurements

a. The Permittee shall install, operate and maintain systems to measure the pressure drop across the baghouse associated with each limestone mill.

b. The Permittee shall maintain the records of the measurements made by these systems and records of maintenance and operational activity associated with the systems.

2.11 Recordkeeping

a. The Permittee shall maintain files, which shall be kept current, that contain:

i. A. For the baghouses or other filter devices associated with affected units, design specifications for the device (type of device, maximum design exhaust flow (acfm or scfm), filter area, type of filter cleaning, performance guarantee for particulate exhaust loading in gr/scf, etc.), the manufacturer’s recommended operating and maintenance procedures for the device, and design specification for the filter material in each device (type of material, surface treatment(s) applied to material, weight, performance guarantee, warranty provisions, etc.).

B. In addition, for each baghouse associated with a limestone mill, the normal range of pressure drop across the device and the minimum and maximum safe pressure drop for the device, with supporting documentation.

ii. For the burners in the affected limestone drying mills, the manufacturer’s rated heat input and guarantees or design data for emissions of NOx, CO and VOM.

iii. The designated particulate matter emission rate, in pounds/hour, from each stack or vent associated with the affected units, other than those units individually addressed by Table III. For each category of affected unit (e.g., receiving and handling), the sum of these emission rates and the hourly limitations for any units that are addressed individually shall not exceed the hourly subtotal in Table III for the category of affected unit. (See also Condition 2.

b. i. The Permittee shall keep records for the amount of each bulk material received by or shipped from the plant (tons/month).

ii. The Permittee shall keep records for any incident in bulk materials were deposited outside of a building, with detailed explanation and a description of the practices used to minimize emissions.

c. For affected units that are subject to NSPS, the Permittee shall fulfill applicable recordkeeping requirements of the NSPS, 40 CFR 60.676

d. The Permittee shall keep inspection and maintenance logs for each control device associated with an affected unit.

e. The Permittee shall maintain records documenting implementation of the fugitive emission operating program required by Condition 2.6, including:

i. Records for inspections to verify the implementation of continuous control measures (that are to be in place whenever an affected unit is in operation), including the date and time, the name of the responsible party, identification of the affected unit(s) that were inspected, and the observed condition of control measures;

ii. Records for the implementation of intermittent control measures, i.e., application of suppressants including identification of the affected unit, identification of the suppressant, application rate, dates or date and time of applications, and quantity of total suppressant applied;

iii. Records for application of physical or chemical control agents other than water including the name of the agent; target application concentration, if diluted with water; target application rate; and usage of the agent, gallons/month; and

iv. A log recording incidents when control measures were not present or were not used for an affected unit when it was in operation, including description, date, duration, and a statement of explanation.

f. The Permittee shall record any period during which an affected unit was in operation when its baghouse was not in operation or was not operating properly, as follows:

i. Each period when the pressure drop of a baghouse for a limestone drying system, as measured pursuant to Condition 2.9, deviated outside the levels set as good air pollution control practice (date, duration and description of the event).

ii. Each period when a baghouse failed to operate properly, which records shall include at least the information specified by General Condition 3 (Section 6, Condition 3).

iii. Each period during which an affected unit deviated from the requirements of this permit, including applicable emission limits, which records shall include at least the information specified by General Condition 3 (Section 6, Condition 3).

g. The Permittee shall keep records for all opacity observations made in accordance with USEPA Method 9 for affected units that it conducts or that are conducted on its behalf by individuals who are certified to make such observations. For each occasion on which such observations are made, these records shall include the identity of the observer, a description of the various observations that were made, the observed opacity from individual units, and copies of the raw data sheets for the observations.

h. The Permittee shall maintain the following records for the emissions of the affected units:

i. Records of emissions of particulate matter based on operating data for the unit(s) and appropriate emission factors, with supporting documentation.

ii. Records of emissions of emissions of NO_x, CO and VOM from affected units drying limestone based on fuel usage, operating data and appropriate emission factors, with supporting documentation.

2.12 Notifications

The Permittee shall notify the Illinois EPA within 30 days of deviations from applicable emission standards or operating requirements that continue* for more than 24 hours. These notifications shall include the information specified by General Condition 5 (Section 6, Condition 5).

* For this purpose, time shall be measured from the start of a particular event. The absence of a deviation for a short period shall not be considered to end the event if the deviation resumes. In such circumstances, the event shall be considered to continue until corrective actions are taken so that the deviation ceases or the Permittee takes the affected unit out of service for repairs.

2.13 Reporting

a. The Permittee shall submit quarterly reports to the Illinois EPA for all deviations from emission standards, including standards for visible emissions and opacity, and operating requirements set by this permit for affected units. These notifications shall include the information specified by General Condition 5 (Section 6, Condition 5)

b. These reports shall also address any deviations from applicable compliance procedures established by this permit for affected units.

2.14 Operating Flexibility

The Permittee is authorized to construct and operate affected units that are different from those described in the application as follows without obtaining prior approval by the Illinois EPA. This condition does not affect the Permittee's obligation to comply with the applicable requirements for affected units:

a. This authorization only extends to changes that result from the detailed design of the plant and any refinements to that design that occur during construction and the initial operation of the plant.

b. With respect to air quality impacts, these changes shall generally act to improve dispersion and reduce impacts, as emissions from individual units are lowered, units are moved apart or away from the fence line, stack heights are increased, and heights of nearby structures is reduced.

c. The Permittee shall notify the Illinois EPA prior to proceeding with any changes. In this notification, the Permittee shall describe the proposed changes and explain why the proposed changes will act to reduce impacts, with detailed supporting documentation.

d. Upon written request by the Illinois EPA, the Permittee shall promptly have dispersion modeling performed to demonstrate that the overall effect of the changes is to reduce air quality impacts, so that impacts from affected units remain at or below those predicted by the air quality analysis accompanying the application.

UNIT-SPECIFIC CONDITION 3: CONDITIONS FOR COOLING TOWERS

3.1 Description of Emission Units

The affected units for the purpose of these unit-specific conditions are two mechanical draft wet cooling towers associated with the steam cycle for each CFB boiler. The cooling towers are sources of particulate matter because of mineral material present in the water, which is emitted to the atmosphere due to water droplets that escape from the cooling tower or completely evaporate. The emissions of particulate matter are controlled by drift eliminators at the top of the towers, which collect water droplets entrained in the air exhausted from the cooling towers.

3.2 Control Technology Determination

The affected units shall be equipped, operated, and maintained with drift eliminators designed to limit the loss of water droplets from the unit to not more than 0.0005 percent of the circulating water flow.

3.2 Applicable Federal Emission Standards

None

3.4 Applicable State Emission Standards

Visible emission of fugitive particulate matter from the affected units shall comply with the provisions of 35 IAC 212.301, which provides that visible emissions of fugitive particulate matter shall not be visible from any process, including any material handling or storage activity, when looking generally toward the zenith at a point beyond the property line of the source, except as provided by 35 IAC 212.314.

3.5 Applicability of Other Regulations

None

3.6 Operating Requirements

a. Chromium-based water treatment chemicals, as defined in 40 CFR 63.401, shall not be used in the affected units.

b. i. A. The Permittee shall equip the affected units with appropriate features, such as steam reheat, to enable them to be operated without a significant contribution to fogging and icing on offsite roadways during periods when fogging or icing are present in the area or weather conditions are conducive to fogging or icing.

B. Notwithstanding the above, the Permittee need not include such features in the affected units if it demonstrates by appropriate analysis, as approved in writing by the Illinois EPA, that the cooling towers will be sited and designed and can be operated such that additional features are not needed to prevent a significant contribution to fogging and icing on offsite roadways.

ii. No later than 30 days after completion of the detailed design of the affected units and at least 60 days before construction of the affected units is begun, the Permittee shall submit a summary of the detailed design to the Illinois EPA and either:

A. A detailed description of the physical features that will be included in the affected units to satisfy Condition 3.6(b)(i)(A), the practices that would be followed for such features, and a demonstration that such features will be sufficient to prevent a significant contribution to fogging and icing on offsite roadways, for review and comment by the Illinois EPA; or

B. An analysis pursuant to Condition 3.6(b)(i)(B), including any operational practices that would be followed for the affected units to prevent a significant contribution to fogging and icing on offsite roadways, for review and approval by the Illinois EPA.

c. The Permittee shall operate and maintain the affected units, including the drift eliminators, in a manner consistent with good air pollution control practice for minimizing emissions.

d. The Permittee shall operate and maintain the affected units in accordance with written operating procedures, which procedures shall be kept current. These procedures shall address the practices that will be followed as good air pollution control practice and the actions that will be followed to prevent a significant contribution to icing and fogging on offsite roadways.

3.7 Emission Limitations

The total annual emissions of particulate matter from the affected units shall not exceed 8.4 tons/year, as determined by appropriate engineering calculations.

3.8 Emission Testing

None

3.9 Emission Monitoring

None

3.10 Operational Monitoring and Measurements

a. The Permittee shall measure the total dissolved solids content in the water being circulated in the affected units on at least a monthly basis. Measurements of the total dissolved solids content in the wastewater discharge associated with the affected units, as required by a National Pollution Discharge Elimination System permit, may be used to satisfy this requirement if the effluent has not been diluted or otherwise treated in a manner that would significantly reduce its total dissolved solids content.

b. Upon written request by the Illinois EPA, the Permittee shall promptly have the water circulating in the affected units sampled and analyzed for the presence of hexavalent chromium in accordance with the procedures of 40 CFR 63.404(a) and (b).

3.11 Records

a. The Permittee shall keep a file that contains:

i. The design loss specification for the drift eliminators installed in each affected unit.

ii. The suppliers recommended procedures for inspection and maintenance of the drift eliminators.

iii. The operating factors, if any, used to determine the amount of water circulated in the affected units or the particulate matter emissions from the affected units, with supporting documentation.

iv. Copies of the Material Safety Data Sheets or other comparable information from the suppliers for the various water treatment chemicals that are added to the water circulated in the affected units.

b. The Permittee shall keep the following operating records for the affected units:

i. The amount of water circulated in the affected units, gallons/month. As an alternative to direct data for water flow, these records may contain other relevant operating data for the units (e.g., water flow to the units) from which the amount of water circulated in the units may be reasonably determined.

ii. Each occasion when the Permittee took action to prevent a significant contribution to fogging or icing from the affected units, including the date and duration, the action or actions that were taken, the weather conditions that triggered such actions, and the weather conditions when actions were terminated.

c. The Permittee shall keep inspection and maintenance logs for the drift eliminators installed in each affected unit.

d. The Permittee shall maintain records for the particulate matter emissions of the affected units based on the above records, the measurements required by Condition 3.10(a), and appropriate USEPA emission estimation methodology and emission factors, with supporting calculations.

3.12 Notifications

The Permittee shall notify the Illinois EPA within 30 days of deviations from applicable requirements for an affected unit. These notifications shall include the information specified by General Condition 4 (Section 6, Condition 4).

UNIT-SPECIFIC CONDITION 4: CONDITIONS FOR THE AUXILIARY BOILER

4.1 Description of Emission Unit

The affected unit for the purpose of these unit-specific conditions is the auxiliary boiler for the plant, which is fired with natural gas. The auxiliary boiler is used to produce low-pressure steam to maintain the plant when the coal-fired boilers are not in operation and support the startup of the coal-fired boilers.

4.2 List of Emission Units and Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
Boiler	Natural Gas-Fired Boiler, with Rated Heat Input Capacity of no More Than 99 Million Btu/Hr	Low-NO_x Burner

4.2 Control Technology Determination

a. The only fuel burned in the affected boiler shall be natural gas.

b. The emissions from the boiler shall not exceed the following limits except during startup, shutdown and malfunction as addressed by Condition 1.2(c).

i. NO_x - 0.08 lb/million Btu.

This limit shall apply as a 3-hour block average, with compliance determined by emission testing in accordance with Condition 4.8 and proper operation.

ii. CO - 0.1 lb/million Btu.

This limit shall apply as a 3-hour block average, with compliance determined by emission testing in accordance with Condition 4.8 and proper operation.

iii. VOM – 0.02 lb/million.

This limit shall apply as a 3-hour block average, with compliance determined by emission testing in accordance with Condition 4.8 and proper operation.

c. The Permittee shall use reasonable practices to minimize emissions during startup, shutdown and malfunction of the affected boiler, including:

i. Operation of the boiler and associated air pollution control equipment in accordance with written operating procedures that include startup, shutdown and malfunction plan(s); and

ii. Inspection, maintenance and repair of the boiler and associated air pollution control equipment in accordance with written maintenance procedures.

4.3 Applicable Federal Emission Standards

a. The affected boiler is subject to a New Source Performance Standard (NSPS) for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Dc, and related provisions in Subpart A.

b. At all times, the Permittee shall maintain and operate the affected boiler, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions, pursuant to 40 CFR 60.11(d).

c. This permit reflects a determination by the Illinois EPA that the affected boiler is not subject to emission standards under the NSPS because the boiler does not burn oil or solid fuel.

4.4 Applicable State Emission Standards

a. The emission of smoke or other particulate matter from the affected boiler shall not have an opacity greater than 30 percent, except as allowed by 35 IAC 212.124. Compliance with this limit shall be determined by 6-minute averages of opacity measurements in accordance with USEPA Reference Method 9. [35 IAC 212.109 and 212.123(a)]

b. The emission of carbon monoxide (CO) into the atmosphere from the affected boiler shall not exceed 200 ppm, corrected to 50 percent excess air. [35 IAC 216.121]

4.5 Applicability of Regulations of Concern

This permit is issued on the affected boiler not being an electrical generating unit, so that provisions of the federal Acid Rain Program are not applicable to the boiler.

4.6 Operating Requirements

a. The affected boiler shall only be fired with natural gas.

b. The rated heat input of the affected boiler shall not exceed 99 million Btu/hour.

c. The affected boiler shall not operate for more than 2500 hours per year when a CFB boiler is in operation. Compliance with this limit shall be determined from a running total of 12 months of data.

4.7 Emission Limitations

Emissions of NO_x, VOM, CO, PM and SO2 from the affected boiler shall not exceed 9.9, 2.5, 12.4, 1.2 and 0.7 tons/year, respectively. Compliance with these annual limits shall be determined on a monthly basis from the sum of the data for the current month plus the preceding 11 months.

4.8 Emission Testing

a. i. Within 60 days after achieving the maximum production rate at which the affected boiler will be operated but not later than 180 days after initial startup of the boiler, the Permittee shall have tests conducted for opacity and emissions of NO_x, CO and VOC as follows at its expense by an approved testing service while the boiler is operating at maximum operating load and other representative operating conditions.

ii. In addition to the emission testing required above, the Permittee shall perform emission tests as requested by the Illinois EPA for the affected boiler within 45 days of a written request by the Illinois EPA or such later date agreed to by the Illinois EPA.

b. The following methods and procedures shall be used for testing, unless otherwise specified or approved by the Illinois EPA.

Opacity	Method 9
Location of Sample Points	Method 1
Gas Flow and Velocity	Method 2
Flue Gas Weight	Method 3 or 3A
Moisture	Method 4
Nitrogen Oxides[1]	Method 7, 7E or 19 as specified in 40 CFR 60.48b
Carbon Monoxide	Method 10
Volatile Organic Compounds	Method 25A and 18

c. Test plans, test notifications, and test reports shall be submitted to the Illinois EPA in accordance with the General Condition 2 (Section 6, Conditions 2)

4.9 Operational Monitoring and Measurements

None

4.10 Emission Monitoring

None

4.11 Recordkeeping

a. The Permittee shall keep a file that contains:

i. The rated heat input capacity of the affected boiler as provided by the manufacturer or subsequently determined based on the demonstrated heat input capacity of the boiler.

b. The Permittee shall maintain the following operating records for the affected boiler:

i. An operating log or other record that among other matters identifies each period when the boiler is operated.

ii. A summary of operating hours (hours/month and hours/year) for all operation and for operation when a CFB boiler was operating.

iii. Natural gas usage on a monthly basis (million Btu or cubic feet).

c. The Permittee shall maintain a maintenance and repair log for the affected boiler.

d. The Permittee shall keep records of the annual NO_x, VOM, CO, PM and SO_2 emissions from the affected boiler, based on fuel consumption, operating data, and applicable emission factors, with supporting calculations.

4.12 Notifications

The Permittee shall notify the Illinois EPA within 30 days of deviations from applicable requirements. These notifications shall include the information specified by General Condition 4 (Section 6, Condition 4).

4.13 Reporting

The Permittee shall fulfill applicable reporting requirements of the NSPS, 40 CFR 60.49b, for the affected boiler by sending the following notifications and reports to the Illinois EPA:

a. The Permittee shall submit notification of the date of initial startup of the boiler, as provided by 40 CFR 60.7. This notification shall include: (1) the design heat input of the boiler, and (2) the annual capacity factor at which the Permittee anticipates operating the boiler. [40 CFR 60.49c(a)]

4.14 Operational Flexibility/Anticipated Operating Scenarios

None

4.15 Compliance Procedures

Compliance with the emission limits in Condition 4.7 shall be based on the operating records required by Condition 4.11 and appropriate emission factors.

a. The emission factors for NO_x, CO, and VOM shall be based on the results of the emission testing required by Condition 4.8.

b. The following emission factors may be used for PM and SO_2 when the affected boiler operates properly. These are the emission factors for small natural gas fired boilers from USEPA's *Compilation of Air Pollutant Emission Factors*, AP-42, October 1996.

Pollutant	Emission Factor (lb/million ft^3)
PM	3.0
SO_2	0.6

UNIT-SPECIFIC CONDITION 5: CONDITIONS FOR ROADWAYS AND OTHER OPEN AREAS

5.1 Description of Emission Units

The affected units for the purpose of these unit-specific conditions are roadways, parking areas and open areas at the plant, which may be sources of fugitive particulate matter due to vehicle traffic or wind blown dust.

5.2 Control Technology Determination

a. Good air pollution control practices shall be implemented to minimize and significantly reduce nuisance dust from affected units. After construction of the plant is complete, these practices shall provide for pavement on all regularly traveled roads and treatment (flushing, vacuuming, dust suppressant application, etc.) of paved and unpaved roads and areas that are routinely subject to vehicle traffic for very effective and effective control of dust, respectively (nominal 90 percent for paved roads and areas and 80 percent control for unpaved roads and areas).

b. For this purpose, roads that serve the main office, or are used on a daily basis by operating and maintenance personnel for the plant or by security personnel in the course of their typical duties, or experience heavy use during regularly occurring maintenance of the plant during the course of a year, shall all be considered subject to regular travel and required to be paved. Regularly traveled roads shall be considered to be subject to routine vehicle traffic except as they are used primarily for periodic maintenance and are currently inactive or as traffic has been temporarily blocked off. Other roads shall be considered to be subject to routine travel if activities are occurring such that the roads are experiencing significant vehicle traffic.

5.3 Applicable Federal Emission Standards

None

5.4 Applicable State Emission Standards

a. Affected units shall comply with 35 IAC 212.301, which provides that visible emissions of fugitive particulate matter shall not be visible from any process, including any material handling or storage activity, when looking generally toward the zenith at a point beyond the property line of the source, except as provided by 35 IAC 212.314.

b. The handling of material collected from affected unit by sweeping or vacuuming trucks shall comply with 35 IAC 212.307, which provides that all unloading and transportation of materials collected by pollution control equipment shall be enclosed or shall utilize spraying, pelletizing, screw conveying or other equivalent methods [35 IAC 212.307].

5.5 Applicability of Other Regulations

This permit reflects a determination by the Illinois EPA that the source is a power plant or electrical generating operation so that the provisions of 35 IAC 212.306 are not applicable to roads and parking areas at the source. [35 IAC 212.306]

5.6 Operating Requirements

a. i. The Permittee shall carry out control of fugitive particulate matter emissions from affected units in accordance with a written operating program describing the measures being implemented in accordance with Conditions 5.2 and 5.4 to control emissions at each unit with the potential to generate significant quantities of such emissions, which program shall be kept current.

A. This program shall include maps or diagrams indicating the location of affected units with the potential to generate significant quantities of fugitive particulate matter, with description of the unit (length, width, surface material, etc.), the volume and nature of expected vehicle traffic or other activity on such unit, and an identification of any roadways that are not considered regularly traveled, with justification.

B. This program shall include a detailed description of the emissions control technique (e.g., vacuum truck, water flushing, or sweeping) for the affected unit, including: typical application rate; type and concentration of additives; normal frequency with which measures would be implemented; circumstances, in which the measure would not be implemented, e.g., recent precipitation; triggers for additional control, e.g. observation of 10 percent opacity; and calculated control efficiency for particulate matter emissions.

ii. The Permittee shall submit copies of this operating program to the Illinois EPA for review as follows:

A. A program addressing the construction of the plant shall be submitted within 30 days of beginning actual construction of the plant.

B. A program addressing the operation of the plant shall be submitted within 90 days of initial start up of the plant.

C. Significant amendments to the program by the Permittee shall be submitted within 30 days.

iii. A revised operating program shall be submitted to the Illinois EPA for review within 90 days of a request from the Illinois EPA for revision to address observed deficiencies in control of fugitive particulate emissions.

b. The Permittee shall conduct inspections of affected units on at least a weekly basis during construction of the plant and on a monthly basis thereafter to verify that the measures identified in the operating program and other measures required to control emissions from affected units are being properly implemented.

5.7 Emission Limitations

The total annual emissions of particulate matter from the affected units shall not exceed 5.5 tons/year, as determined by appropriate engineering calculations.

5.8 Emission Testing

None

5.9 Operational Monitoring and Measurements

None

5.10 Emission Monitoring

None

5.11 Records

a. The Permittee shall keep a file that contains:

i. The operating factors, if any, used to determine the amount of activity associated with the affected units or the particulate matter emissions from the affected units, with supporting documentation.

b. The Permittee shall maintain records documenting implementation of the operating program required by Condition 5.6, including:

i. For each treatment of an affected unit or units, the name and location of the affected unit(s), the date and time, and the identification of the truck(s) or treatment equipment used;

ii. For each application of water or chemical solution by truck: application rate of water or suppressant, frequency of each application, width of each application, total quantity of water or chemical used for each application and, for each application of chemical solution, the concentration and identity of the chemical;

iii. For application of physical or chemical control agents: the name of the agent, application rate and frequency, and total quantity of agent and, if diluted, percent of concentration, used each day; and

iv. A log recording incidents when control measures were not used and incidents when additional control measures were used due to particular activities, including description, date, a statement of explanation, and expected duration of the such circumstances.

c. The Permittee shall record any period during which an affected unit was not properly controlled as required by this permit, which records shall include at least the information specified by General Condition 3 (Section 6, Condition 3) and an estimate of the additional emissions of particulate matter that resulted, if any, with supporting calculations.

d. The Permittee shall maintain records for the particulate matter emissions of the affected units based on plant operating data, the above records for the affected unit including data for implementation of the operating program, and appropriate USEPA emission estimation methodology and emission factors, with supporting calculations.

5.12 Notifications

The Permittee shall notify the Illinois EPA within 30 days of deviations from applicable requirements for affected units that are not addressed by the regular reporting required below. These notifications shall include the information specified by General Condition 4 (Section 6, Condition 4).

5.13 Reporting

The Permittee shall submit a quarterly report to the Illinois EPA for affected units stating the following: the dates any necessary control measures were not implemented, a listing of those control measures, the reasons that the control measures were not implemented, and any corrective actions taken. This information includes, but is not limited to, those dates when controls were not applied based on a belief that application of such control measures would have been unreasonable given prevailing atmospheric conditions. This report shall be submitted to the Illinois EPA no later than 45 calendar days from the end of each calendar quarter.

SECTION 5: TRADING PROGRAM CONDITIONS

TRADING PROGRAM CONDITION 1: ACID RAIN PROGRAM REQUIREMENTS

a. Applicability

Under Title IV of the Clean Air Act, Acid Deposition Control, this plant or source is an affected source and the following emission units at the source are affected units for acid deposition:

Circulating Fluidized Bed Boilers 1 and 2

Note: Title IV of the Clean Air Act, and other laws and regulations promulgated thereunder, establish requirements for affected sources related to control of emissions of pollutants that contribute to acid rain. For purposes of this permit, these requirements are referred to as Title IV provisions.

b. Applicable Emission Requirements

The owners and operators of the source shall not violate applicable Title IV provisions. In particular, SO_2 emissions of the affected units shall not exceed any allowances that the source lawfully holds under Title IV provisions. [Environmental Protection Act, Sections 39.5(7)(g) and (17)(l)]

Note: Affected sources must hold SO_2 allowances to account for the SO_2 emissions from affected units at the source that are subject to Title IV provisions. Each allowance is a limited authorization to emit up to one ton of SO_2 emissions during or after a specified calendar year. The possession of allowances does not authorize exceedances of applicable emission standards or violations of ambient air quality standards.

c. Monitoring, Recordkeeping and Reporting

The owners and operators of the source and, to the extent applicable, their designated representative, shall comply with applicable requirements for monitoring, recordkeeping and reporting specified by Title IV provisions, including 40 CFR Part 75. [Environmental Protection Act, Sections 39.5(7)(b) and 17(m)]

Note: As already addressed in Unit-Specific Condition 1, the following emission determination methods would be used for the affected units at this source.

NO_x:	Continuous emissions monitoring (40 CFR 75.12)
SO_2:	Continuous emissions monitoring (40 CFR 75.11)
Opacity:	Continuous emission monitoring (40 CFR 75.14)
O_2/CO_2:	Continuous monitoring for oxygen or carbon dioxide (40 CFR 75.13)

d. Acid Rain Permit

The owners and operators of the source shall comply with the terms and conditions of the source's Acid Rain permit. [Environmental Protection Act, Section 39.5(17)(l)]

Note: The source is subject to an Acid Rain permit, which was issued pursuant to Title IV provisions, including Section 39.5(17) of the Act. Affected sources must be operated in compliance with their Acid Rain permits. The initial Acid Rain permit is included as an attachment to this permit. Revisions and modifications of this Acid Rain permit, including administrative amendments and automatic amendments (pursuant to Sections 408(b) and 403(d) of the CAA or regulations thereunder) are governed by Title IV provisions, as provided by Section 39.5(13)(e) of the Environmental Protection Act, and revision or renewal of the Acid Rain permit may be handled separately from this permit.

e. Coordination with Other Requirements

i. This permit does not contain any conditions that are intended to interfere with or modify the requirements of Title IV provisions. In particular, this permit does not restrict the flexibility under Title IV provisions of the owners and operators of this source to amend their Acid Rain compliance plan. [Environmental Protection Act, Section 39.5(17)(h)]

ii. Where another applicable requirement of this permit is more stringent than an applicable requirement of Title IV provisions, both requirements are enforceable and the owners and operators of the source shall comply with both requirements. [Environmental Protection Act, Section 39.5(7)(h)]

TRADING PROGRAM CONDITION 2: EMISSIONS REDUCTION MARKET SYSTEM (ERMS)

a. Description of ERMS

The ERMS is a “cap and trade” market system for major stationary sources located in the Chicago ozone nonattainment area. It is designed to reduce VOM emissions from stationary sources to contribute to reasonable further progress toward attainment, as required by Section 182(c) of the CAA.

The ERMS addresses VOM emissions during a seasonal allotment period from May 1 through September 30. Participating sources must hold “allotment trading units” (ATUs) for their actual seasonal VOM emissions. Each year participating sources are issued ATUs based on allotments set in the sources’ CAAPP permits. These allotments are established from historical VOM emissions or “baseline emissions” lowered to provide the emissions reductions from stationary sources required for reasonable further progress.

By December 31 of each year, the end of the reconciliation period following the seasonal allotment period, each source shall have sufficient ATUs in its transaction account to cover its actual VOM emissions during the preceding season. A transaction account’s balance as of December 31 will include any valid ATU transfer agreements entered into as of December 31 of the given year, provided such agreements are promptly submitted to the Illinois EPA for entry into the transaction account database. The Illinois EPA will then retire ATUs in sources’ transaction accounts in amounts equivalent to their seasonal emissions. When a source does not appear to have sufficient ATUs in its transaction account, the Illinois EPA will issue a notice to the source to begin the process for Emissions Excursion Compensation.

In addition to receiving ATUs pursuant to their allotments, participating sources may also obtain ATUs from the market, including ATUs bought from other participating sources and general participants in the ERMS that hold ATUs (35 IAC 205.630). During the reconciliation period, sources may also buy ATUs from a secondary reserve of ATUs managed by the Illinois EPA, the “Alternative Compliance Market Account” (ACMA) (35 IAC 205.710). Sources may also transfer or sell the ATUs that they hold to other participants (35 IAC 205.630).

b. Applicability

This plant or source is considered a “new participating source” for purposes of the ERMS, 35 IAC Part 205.

c. Obligation to Hold Allotment Trading Units (ATUs)

In accordance with 35 IAC 205.150(d)(1), at the end of the reconciliation period each year, once the source commences operation, the source shall hold ATUs in an amount not less than 1.3 times its VOM emissions during the preceding seasonal allotment period (May 1 through September 30), determined in accordance with applicable provisions in Section 3 of this permit or the source’s CAAPP permit, not including VOM emissions from the following, or the source shall be subject to “emissions excursion compensation,” as described in Condition 2(e):

i. VOM emissions from insignificant emission units, if any, as identified in the source’s CAAPP permit, in accordance with 35 IAC 205.220;

ii. Excess VOM emissions associated with startup, malfunction, or breakdown of an emission unit as authorized by 35 IAC 201.262, if any, in accordance with 35 IAC 205.225;

iii. Excess VOM emissions that are a consequence of an emergency at the source as approved by the Illinois EPA, in accordance with 35 IAC 205.750; and

iv. Excess VOM emissions to the extent allowed by a Variance, Consent Order, or Compliance Schedule, in accordance with 35 IAC 205.320(e)(3).

d. Market Transactions

i. The source shall apply to the Illinois EPA for and obtain authorization for a Transaction Account prior to conducting any market transactions, as specified at 35 IAC 205.610(a).

ii. The source shall promptly submit to the Illinois EPA any revisions to the information submitted for its Transaction Account, pursuant to 35 IAC 205.610(b).

iii. The source shall have at least one account officer designated for its Transaction Account, pursuant to 35 IAC 205.620(a).

iv. Any transfer of ATUs to or from the source from another source or general participant must be authorized by a qualified Account Officer designated by the source and approved by the Illinois EPA, in accordance with 35 IAC 205.620, and the transfer must be submitted to the Illinois EPA for entry into the Transaction Account database.

e. Emissions Excursion Compensation

Pursuant to 35 IAC 205.720, if the source fails to hold ATUs in accordance with Condition 2(c), it shall provide emissions excursion compensation in accordance with the following:

i. Upon receipt of an Excursion Compensation Notice issued by the Illinois EPA, the source shall purchase ATUs from the ACMA in the amount specified by the notice, as follows:

A. The purchase of ATUs shall be in an amount equivalent to 1.2 times the emissions excursion; or

B. If the source had an emissions excursion for the seasonal allotment period immediately before the period for the present emissions excursion, the source shall purchase ATUs in an amount equivalent to 1.5 times the emissions excursion.

ii. If requested in accordance with Condition 2(e)(iii) below or in the event that the ACMA balance is not adequate to cover the total emissions excursion amount, the Illinois EPA will deduct ATUs equivalent to the specified amount or any remaining portion thereof from the ATUs issued to the source for the next seasonal allotment period.

iii. Pursuant to 35 IAC 205.720(c), within 15 days after receipt of an Excursion Compensation Notice, the owner or operator may request that ATUs equivalent to the amount specified be deducted from the source’s next seasonal allotment by the Illinois EPA, rather than purchased from the ACMA.

f. Quantification of Seasonal VOM Emissions

i. The methods and procedures specified in Sections 4 of this permit (Unit-Specific Conditions) or the CAAPP permit for the source shall be used for determining seasonal VOM emissions for purposes of the ERMS.

ii. The Permittee shall report emergency conditions at the source to the Illinois EPA, in accordance with 35 IAC 205.750, if the Permittee intends to deduct VOM emissions that are in excess of a technology-based VOM emission rate normally achieved and are attributable to the emergency from the source’s seasonal VOM emissions for purposes of the ERMS. These reports shall include the information specified by 35 IAC 205.750(a), and shall be submitted in accordance with the following:

A. An initial emergency conditions report within two days after the time when such excess emissions occurred due to the emergency; and

B. A final emergency conditions report, if needed to supplement the initial report, within 10 days after the conclusion of the emergency.

g. Annual Account Reporting

i. For each year in which the source is operational, the Permittee shall submit, as a component of its Annual Emissions Report, seasonal VOM emissions information to the Illinois EPA for the seasonal allotment period. This report shall include the following information [35 IAC 205.300]:

A. Actual seasonal emissions of VOM from the source;

B. A description of the methods and practices used to determine VOM emissions, as required by this permit, including any supporting documentation and calculations;

C. A detailed description of any monitoring methods that differ from the methods specified in this permit, as provided in 35 IAC 205.337;

D. If the source has experienced an emergency, as provided in 35 IAC 205.750, the report shall reference the associated emergency conditions report that has been approved by the Illinois EPA;

ii. This report shall be submitted by October 31 of each year, for the preceding seasonal allotment period.

h. Allotment of ATUs to the Source

i. As a new participating source, the source will not receive allotments of ATUs from the State of Illinois.

ii. A. If the source enters into a multiple season transfer agreement with another participating source or a general participant in the ERMS, ATUs will be issued to the source's Transaction Account by the Illinois EPA annually for the duration of such agreement. These ATUs will be valid for the seasonal allotment period for which they are issued and, if not retired for this period, the next seasonal allotment period.

B. Notwithstanding the above, part or all of the above ATUs will not be issued to the source in circumstances as set forth in 35 IAC Part 205, including:

1. Transfer of ATUs by the source to another participant or the ACMA, in accordance with 35 IAC 205.630;

2. Deduction of ATUs as a consequence of emissions excursion compensation, in accordance with 35 IAC 205.720.

i. Recordkeeping for ERMS

i. The Permittee shall maintain the following records related to actual VOM emissions of the source during the seasonal allotment period:

A. Records of operating data and other information for each individual emission unit or group of related emission units at the source, as specified in Section 4 of this permit and in the source’s CAAPP permit, as appropriate, to determine actual VOM emissions during the seasonal allotment period;

B. Records of the VOM emissions, in tons, during the seasonal allotment period, with supporting calculations, for each individual emission unit or group of related emission units at the source, determined in accordance with the procedures specified in Section 4 of this permit and in the source’s CAAPP permit; and

C. Total VOM emissions from the source, in tons, during each seasonal allotment period, which shall be compiled by October 31, of each year.

ii. The Permittee shall maintain copies of the following documents as its Compliance Master File for purposes of the ERMS [35 IAC 205.335 and 205.700(a)]:

A. Seasonal component of the Annual Emissions Report;

B. Information on actual VOM emissions, as specified in detail in Section 4 of this permit and in the source's CAAPP permits; and

C. Any transfer agreements for the purchase or sale of ATUs and other documentation associated with the transfer of ATUs.

TRADING PROGRAM CONDITION 3: NO_x TRADING PROGRAM

a. Description of NO_x Trading Program

The NO_x Trading Program is a regional "cap and trade" market system for large sources of NO_x emissions in the eastern United States, including Illinois. It is designed to reduce and maintain NO_x emissions from the emission units covered by the program within a budget to help contribute to attainment and maintenance of the ozone ambient air quality standard in the multi-state region covered by the program, as required by Section 110 of the Clean Air Act. The NO_x Trading Program applies in addition to other applicable requirements for NO_x emissions and in no way relaxes these other requirements.

Electrical generating units (EGU) that are subject to the NO_x Trading Program are referred to as "budget EGU." Sources that have one or more EGU or other units subject to the NO_x Trading Program are referred to as budget sources.

The NO_x Trading Program controls NO_x emissions from budget EGU and other budget units during a seasonal control period from May 1 through September 30 of each year, when weather conditions are conducive to formation of ozone in the ambient air. (In 2004, the first year that the NO_x Trading Program is in effect, the control period will be May 31 through September 30.) By November 30 of each year, the allowance transfer deadline, each budget source must hold "NO_x allowances" for the actual NO_x emissions of its budget units during the preceding control period. The USEPA will then retire NO_x allowances in the source's accounts in amounts equivalent to its seasonal emissions. If a source does not have sufficient allowances in its accounts, USEPA would subtract allowances from the source's future allocation for the next control period and impose other penalties as appropriate. Stringent monitoring procedures developed by USEPA apply to budget units to assure that NO_x emissions are accurately determined.

The number of NO_x allowances available for budget sources is set by the overall budget for NO_x emissions established by USEPA. This budget requires a substantial reduction in NO_x emissions from historical levels as necessary to meet air quality goals. In Illinois, existing budget sources initially receive their allocation or share of the NO_x allowances budgeted for EGU in an amount determined by rule [35 IAC Part 217, Appendix F]. Between 2007 and 2011, the allocation mechanism for existing EGU gradually shifts to one based on the actual utilization of EGU in preceding control periods. New budget EGU, for which limited utilization data may be available, may obtain NO_x allowances from the new source set-aside (NSSA), a portion of the overall budget reserved for new EGU.

In addition to directly receiving or purchasing NO_x allowances as described above, budget sources may transfer NO_x allowances from one of their units to another. They may also purchase allowances in the marketplace from other sources that are willing to sell some of the allowances that they have received. Each budget source must designate an account representative to handle all its allowance transactions. The USEPA, in a central national system, will maintain allowance accounts and record transfer of allowances among accounts.

The ability of sources to transfer allowances will serve to minimize the costs of reducing NO_x emissions from budget units to comply with the overall NO_x budget. In particular, the NO_x emissions of budget units that may be most economically controlled will be targeted by sources for further control of emissions. This will result in a surplus of NO_x allowances from those units that can be transferred to other units at which it is more difficult to control NO_x emissions. Experience with reduction of SO_2 emissions under the federal Acid Rain program has shown that this type of trading program not only achieves regional emission reductions in a more cost-effective manner but also results in greater overall reductions than application of traditional emission standards to individual emission units.

The USEPA developed the plan for the NO_x Trading Program with assistance from affected states. Illinois' rules for the NO_x Trading Program for EGU are located in 35 IAC Part 217, Subpart W and have been approved by the USEPA. These rules provide for interstate trading, as mandated by Section 9.9 of the Act. Accordingly, these rules refer to and rely upon federal rules at 40 CFR Part 96, which have been developed by USEPA for certain aspects of the NO_x Trading Program, and which an individual state must follow to allow for interstate trading of NO_x allowances.

Note: This narrative description of the NO_x Trading Program is for informational purposes only and is not enforceable.

b. Applicability

The following emission units at this source are budget EGU for purposes of the NO_x Trading Program. Accordingly, this source is a budget source and the Permittee is the owner or operator of a budget source and budget EGU. In this condition, these emission units are addressed as budget EGU.

Boiler 1
Boiler 2

c. General Provisions of the NO_x Trading Program

i. This source and the budget EGU at this source shall comply with all applicable requirements of Illinois' NO_x Trading Program, i.e., 35 IAC Part 217, Subpart W, and 40 CFR Part 96 (excluding 40 CFR 96.4(b) and 96.55(c), and excluding 40 CFR 96, Subparts C, E and I), pursuant to 35 IAC 217.756(a) and 217.756(f)(2).

ii. Any provision of the NO_x Trading Program that applies to a budget source (including any provision applicable to the account representative of a budget source) shall also apply to the owner or operator of such budget sources and to the owner and operator of each budget EGU at the source, pursuant to 35 IAC 217.756(f)(3).

iii. Any provision of the NO_x Trading Program that applies to a budget EGU (including any provision applicable to the account representative of a budget EGU) shall also apply to the owner and operator of such budget EGU. Except with regard to requirements applicable to budget EGUs with a common stack under 40 CFR 96, Subpart H, the owner and operator and the account representative of one budget EGU shall not be liable for any violation by any other budget EGU of which they are not an owner or operator or the account representative, pursuant to 35 IAC 217.756(f)(4).

d. Requirements for NO_x Allowances

i. By November 30 of each year, the allowance transfer deadline, the account representative of each budget EGU at this source shall hold allowances available for compliance deduction under 40 CFR 96.54 in the budget EGU's compliance account or the source's overdraft account in an amount that shall not be less than the budget EGU's total tons of NO_x emissions for the preceding control period, rounded to the nearest whole ton, as determined in accordance with 40 CFR 96, Subpart H, plus any number necessary to account for actual utilization (e.g., for testing, start-up, malfunction, and shut down under 40 CFR 96.42(e) for the control period, pursuant to 35 IAC 217.756(d)(1). For purposes of this requirement, an allowance may not be utilized for a control period in a year prior to the year for which the allowance is allocated, pursuant to 35 IAC 217.756(d)(5).

ii. The account representative of a budget EGU that has excess emissions in any control period, i.e., NO_x emissions in excess of the number of NO_x allowances held as provided above, shall surrender the allowances as required for deduction under 40 CFR 96.54(d)(1), pursuant to 35 IAC 217.756(f)(5). In addition, the owner or operator of a budget EGU that has excess emissions shall pay any fine, penalty, or assessment, or comply with any other remedy imposed under 40 CFR 96.54(d)(3) and the Act, pursuant to 35 IAC 217.756(f)(6). Each ton of NO_x emitted in excess of the number of NO_x allowances held as provided above for each budget EGU for each control period shall constitute a separate violation of 35 IAC Part 217 and the Act, pursuant to 35 IAC 217.756(d)(2).

iii. An allowance allocated by the Illinois EPA or USEPA under the NO_x Trading Program is a limited authorization to emit one ton of NO_x in accordance with the NO_x Trading Program. As explained by 35 IAC 217.756(d)(6), no provision of the NO_x Trading Program, the budget permit application, the budget permit, or a retired unit exemption under 40 CFR 96.5 and no provision of law shall be construed to limit the authority of the United States or the State of Illinois to terminate or limit this authorization. As further explained by 35 IAC 217.765(d)(7), an allowance allocated by the Illinois EPA or USEPA under the NO_x Trading Program does not constitute a property right. As provided by 35 IAC 217.756(c)(4), allowances shall be held, deducted from, or transferred among allowance accounts in accordance with 35 IAC Part 217, Subpart W, and 40 CFR 96, Subparts F and G.

e. Monitoring Requirements for Budget EGU

i. The Permittee shall comply with the monitoring requirements of 40 CFR Part 96, Subpart H, for each budget EGU and the compliance of each budget EGU with the emission limitation under Condition 3(d)(i) shall be determined by the emission measurements recorded and reported in accordance with 40 CFR 96, Subpart H, pursuant to 35 IAC 217.756(c)(1), (c)(2) and (d)(3).

ii. The account representative for the source and each budget EGU at the source shall comply with those sections of the monitoring requirements of 40 CFR 96, Subpart H, applicable to an account representative, pursuant to 35 IAC 217.756(c)(1) and (d)(3).

f. Recordkeeping Requirements for Budget EGU

Unless otherwise provided below, the Permittee shall keep on site at the source each of the following documents for a period of at least 5 years from the date the document is created. This 5-year period may be extended for cause at any time prior to the end of the 5 years, in writing by the Illinois EPA or the USEPA.

i. The account certificate of representation of the account representative for the source and each budget EGU at the source and all documents that demonstrate the truth of the statements in account certificate of representation, in accordance with 40 CFR 96.13, as provided by 35 IAC 217.756(e)(1)(A). These certificates and documents must be retained on site at the source for at least 5-years after they are superseded because of the submission of a new account certificate of representation changing the account representative.

ii. All emissions monitoring information, in accordance with 40 CFR 96, Subpart H, (provided that to the extent that 40 CFR 96, Subpart H, provides for a 3-year period for retaining records, the 3-year period shall apply,) pursuant to 35 IAC 217.756(e)(1)(B).

iii. Copies of all reports, compliance certifications, and other submissions and all records made or required under the NO_x Trading Program or documents necessary to demonstrate compliance with requirements of the NO_x Trading Program, pursuant to 35 IAC 217.756(e)(1)(C).

iv. Copies of all documents used to complete a budget permit application and any other submission under the NO_x Trading Program, pursuant to 35 IAC 217.756(e)(1)(D).

g. Reporting Requirements for Budget EGU

i. The account representative for this source and each budget EGU at this source shall submit to the Illinois EPA and USEPA the reports and compliance certifications required under the NO_x Trading Program, including those under 40 CFR 96, Subparts D and H and 35 IAC 217.774, pursuant to 35 IAC 217.756(e)(2).

ii. These submittals need only be signed by the designated representative, who may serve in place of the responsible official for this purpose as provided by the Section 39.5(1) of the Act, and submittals to the Illinois EPA need only be made to the Illinois EPA, Bureau of Air, Compliance and Enforcement Section.

h. Allocation of NO_x Allowances to Budget EGU

i. For the first four control periods that a budget EGU identified in Condition 3(b) operates, it will not be entitled to direct allocations of NO_x allowances because the EGU will be considered a “new” budget EGU, as defined in 35 IAC 217.768(a)(1).

ii. A. Thereafter, the budget EGU will cease to be “new” budget EGU and the source will be entitled to an allocation of NO_x allowances for the budget EGU as provided in 35 IAC 217.764. For example, for 2010, the allocation of NO_x allowances would be governed by 35 IAC 217.764(e)(2) and (b)(4).

B. In accordance with 35 IAC 217.762, the theoretical number of NO_x allowances for these budget EGU, calculated as the product of the applicable NO_x emissions rate and heat input as follows, shall be the basis for determining the allocation of NO_x allowances to these EGU:

1. As provided by 35 IAC 217.762(a)(2), the applicable NO_x emission rates for these EGU is 0.010 lb/million Btu or such lower limit as set pursuant to Unit-Specific Condition 1.15. This is the permitted emission rate for these EGU as contained in Unit-Specific Condition 1.2(b)(iii). The permitted NOx emission rate is the applicable rate because it is between 0.15 lb/million Btu and 0.055 lb/million Btu, as provided by 35 IAC 217.762(a)(2).

2. The applicable heat input (million Btu/control period) shall be the average of the two highest heat inputs from the control periods four to six years prior to the year for which the allocation is being made, as provided by 35 IAC 217.762(b)(1).

Note: If the start of the NO_x Trading program is shifted because of a Court Decision, the years defining the different control periods would be considered to be adjusted accordingly, as provided by the Board note following 35 IAC 217.764.

i. Eligibility for NO_x Allowances from the New Source Set-Aside (NSSA)

The Permittee is eligible to obtain NO_x allowances for the budget EGU identified in Condition 3(b) from the NSSA, as provided by 35 IAC 217.768, because the budget EGU are "new" budget EGU.

j. Budget Permit Required by the NO_x Trading Program

i. For this source, this condition of this permit, i.e., Trading Program Condition 3, is the Budget Permit required by the NO_x Trading Program and is intended to contain federally enforceable conditions addressing all applicable NO_x Trading Program requirements. This Budget Permit shall be treated as a complete and segregable portion of this permit, as provided by 35 IAC 217.758(a)(2).

ii. The Permittee and any other owner or operator of this source and each budget EGU at the source shall operate the budget EGU in compliance with this Budget Permit, pursuant to 35 IAC 217.756(b)(2).

iii. No provision of this Budget Permit or the associated application shall be construed as exempting or excluding the Permittee, or other owner or operator and, to the extent applicable, the account representative of a budget source or budget EGU from compliance with any other regulation or requirement promulgated under the CAA, the Act, the approved State Implementation Plan, or other federally enforceable permit, pursuant to 35 IAC 217.756(g).

iv. Upon recordation by USEPA, under 40 CFR 96, Subparts F or G, or 35 IAC 217.782, every allocation, transfer, or deduction of an allowance to or from the budget EGU's compliance accounts or to or from the overdraft account for the budget source is deemed to amend automatically, and become part of, this budget permit, pursuant to 35 IAC 217.756(d)(8). This automatic amendment of this budget permit shall be deemed an operation of law and will not require any further review.

v. No revision of this Budget Permit shall excuse any violation of the requirements of the NO_x Trading Program that occurs prior to the date that the revisions to this permit takes effect, pursuant to 35 IAC 217.756(f)(1).

vi. The Permittee, or other owner or operator of the source, shall reapply for a Budget Permit for the source as required by 35 IAC Part 217, Subpart W and Section 39.5 of the Act. For purposes of the NO_x Trading Program, the application shall contain the information specified by 35 IAC 217.758(b)(2).

SECTION 6: GENERAL PERMIT CONDITIONS

GENERAL PERMIT CONDITION 1: STANDARD CONDITIONS

Standard conditions for issuance of construction permits, attached hereto shall apply to this project, unless superseded by provisions of other permit conditions.

GENERAL PERMIT CONDITION 2: REQUIREMENTS FOR EMISSION TESTING

a. i. At least 60 days prior to the actual date of initial emission testing required by this permit, a written test plan shall be submitted to the Illinois EPA for review. This plan shall describe the specific procedures for testing and shall include at a minimum:

A. The person(s) who will be performing sampling and analysis and their experience with similar tests.

B. The specific conditions, e.g., operating rate and control device operating conditions, under which testing shall be performed including a discussion of why these conditions are appropriate and the means by which the operating parameters will be determined.

C. The specific determinations of emissions that are intended to be made, including sampling and monitoring locations. As part of this plan, the Permittee may set forth a strategy for performing emission testing in the normal load range of the boilers.

D. The test method(s) that will be used, with the specific analysis method if the method can be used with different analysis methods.

ii. As provided by 35 IAC 283.220(d), the Permittee need not submit a test plan for subsequent emission testing that will be conducted in accordance with the procedures used for previous tests accepted by the Illinois EPA or the previous test plan submitted to and approved by the Illinois EPA, provided that the Permittee’s notification for testing, as required below, contains the information specified by 35 IAC 283.220(d)(1)(A), (B) and (C).

b. i. The Permittee shall notify the Illinois EPA prior to performing emission testing required by this permit to enable the Illinois EPA to observe the tests. Notification for the expected date of testing shall be submitted a minimum of 30 days* prior to the expected date, and identify the testing that will be performed. Notification of the actual date and expected time of testing shall be submitted a minimum of 5 working days* prior to the actual date of testing.

* For a particular test, the Illinois EPA may at its discretion accept shorter advance notification provided that it does not interfere with the Illinois EPA's ability to observe testing.

ii. This notification shall also identify the parties that will be performing testing and the set or sets of operating conditions under which testing will be performed.

c. Three copies of the Final Reports for emission tests shall be forwarded to the Illinois EPA within 30 days after the test results are compiled and finalized. At a minimum, the Final Report for testing shall contain:

i. General information, i.e., testing personnel and test dates;

ii. A summary of results;

iii. Description of test method(s), including a description of sampling points, sampling train, analysis equipment, and test schedule;

iv. The operating conditions of the emission unit and associated control devices during testing and any work practice standard established for the unit as result of testing;

v. Data and calculations, including copies of all raw data sheets and records of laboratory analysis, sample calculations, and data on equipment calibration.

GENERAL PERMIT CONDITION 3: REQUIREMENTS FOR RECORDS FOR DEVIATIONS

Except as specified in a particular provision of this permit or in a subsequent CAAPP Permit for the plant, records for deviations from applicable emission standards and control requirements shall include at least the following information: the date, time and estimated duration of the event; a description of the event; the applicable requirement(s) that were not met; the manner in which the event was identified, if not readily apparent; the probable cause for deviation, if known, including a description of any equipment malfunction/breakdown associated with the event; information on the magnitude of the deviation, including actual emissions or performance in terms of the applicable standard if measured or readily estimated; confirmation that standard procedures were followed or a description of any event-specific corrective actions taken; and a description of any preventative measures taken to prevent future occurrences, if appropriate.

GENERAL PERMIT CONDITION 4: RETENTION AND AVAILABILITY OF RECORDS

Except as specified in a particular provision of this permit or in a subsequent CAAPP Permit for the plant, the Permittee shall keep all records, including written procedures and logs, required by this permit at a readily accessible location at the plant for at least five years and shall make such records available for inspection and copying by the Illinois EPA and USEPA.

GENERAL PERMIT CONDITION 5: NOTIFICATION OR REPORTING OF DEVIATIONS

Notifications and reports for deviation from applicable emission standards, control requirements, and compliance procedures shall be submitted as follows, except as specified in a particular provision of this permit or in a subsequent CAAPP Permit for the plant:

a. Notification and reports for deviations include at least the following information: a description of the event, the date and time or duration of the event, information on the magnitude of the deviation, a description of the corrective measures taken, and a description of any preventative measures taken to prevent future occurrences.

b. Exceedances of applicable emissions standards or limitations during periods of startup, malfunction or breakdown, or shutdown shall be considered deviations for purposes of notification and reporting, even if exceedance of the standard or limitation is otherwise provided for by applicable rule or this permit.

GENERAL PERMIT CONDITION 6: GENERAL REQUIREMENTS FOR NOTIFICATION AND REPORTS

a. i. Two copies of notifications and reports required by this permit shall be sent to the following address unless otherwise indicated above:

Illinois Environmental Protection Agency
Division of Air Pollution Control
Compliance and Enforcement Section
P.O. Box 19276
Springfield, Illinois 62794-9276

ii. One copy of notifications and reports required by this permit, except the Annual Emission Report required by 35 IAC Part 254, shall be sent to the Illinois EPA's regional office at the following address unless otherwise indicated above:

Illinois Environmental Protection Agency
Division of Air Pollution Control
9511 West Harrison
Des Plaines, Illinois 60123

b. Quarterly reports shall cover calendar quarters and be submitted no later than 45 days after the end of the calendar quarter if a shorter deadline is not specified in a particular provision of this permit.

c. The Permittee shall submit Annual Emission Reports to the Illinois EPA in accordance with 35 IAC Part 254. For hazardous air pollutants, this report shall include emission information for at least the following pollutants: hydrogen chloride, hydrogen fluoride, mercury, arsenic, beryllium, cadmium, chromium, lead, manganese, and nickel.

ATTACHMENT - TABLES

TABLE I

Emission Limitations for Each CFB Boiler

Pollutant	Pound/Million Btu[1]	Pounds/Hour[2]	Tons/Year	Combined Tons/Year
PM/PM_{10}[3]	0.015	43.8	192	384
NO_x[4]	0.10[4]	292.2	1,280	2,560
SO_2	0.15	438.3	1,920	3,840
CO	0.11[5]	321.4	1,408	2,816
VOM	0.004[5]	11.7	51.2	102.4
Fluorides[6]	----	5.7	25.1	50.2
Sulfuric Acid Mist	----	1.2	5.1	10.2
Beryllium	----	----	----	0.004
Hydrogen Chloride	----	----	----	256
Hydrogen Fluoride	----	----	----	50.2
Mercury	----	----	----	0.05
Lead	----	----	----	0.31

Notes:

1 Compliance with the emission rates expressed in pound/million Btu heat input shall be determined in accordance with the provisions in Condition 1.2(b).

2 Compliance with hourly emission limits shall be based on 24-hour block averages (NO_x, CO and SO_2) and 3-hour block average (VOM, PM/PM_{10}, fluorides, and sulfuric acid mist. Short-term emission rates do not apply during startup, shutdown or malfunction as addressed by Condition 1.6.

3 All particulate matter (PM) measured by USEPA Method 5 shall be considered PM_{10} unless PM emissions are tested by USEPA Method 201 or 201A, as specified in 35 IAC 212.108(a). These PM limits do not address condensable particulate matter. (Condensable particulate was addressed in the particulate matter air quality impact analysis required by the PSD rules. For this purpose, the emission rate for condensable particulate matter was estimated to be 0.035 lb/million Btu.)

4 The NO_x limits are phased, with an initial limit for the demonstration period, and provision for an even lower limit, which limit could be as low as 0.08 pound per million Btu, pursuant to the optimization program required by Conditions 1.2(d) and 1.15.

5 As an alternative to this limitation expressed in pound/million Btu, the boiler may comply with the limitation expressed in pounds/hour.

6 The limit for fluorides is expressed in terms of hydrogen fluorides.

TABLE II

Emission Limitations for
Certain Bulk Material Preparation Operations Involving Gas Combustion

(Pounds per Hour and Tons per Year)

Emission Unit	PM		CO		NO_x		VOM	
	Hourly Rate	Annual Rate	Hourly Rate	Annual Rate	Hourly Rate	Annual Rate	Hourly Rate	Annual Rate
Limestone Preparation								
Dryer/Mill System 1	0.24	1.05	2.4	10.5	0.9	3.85	0.24	1.05
Dryer/Mill System 2	0.24	1.05	2.4	10.5	0.9	3.85	0.24	1.05
Dryer/Mill System 3	0.24	1.05	2.4	10.5	0.9	3.85	0.24	1.05
Totals		3.15		31.5		11.5		3.2

TABLE III

Particulate Matter (PM) Emission Limitations for
Bulk Material Handling Operations

(Grains Per Dry Cubic Foot, Pounds Per Hour, and Tons Per Year)

Emission Units	Exhaust Loading	Hourly Rate	Annual Rate
Receiving and Handling			
Railcar Unloading, Transfer House, Crusher Building, Hoppers, etc., Except as Below	0.001	0.714	3.13
Limestone Reclaim	0.005	0.086	0.38
Material Storage Buildings	--	--	0.24
Subtotal		0.80	3.75
Limestone Preparation			
Preparation Equipment, Except as Below	0.001	0.270	0.117
Dryer/Mill System 1*	0.001	0.240	1.05
Dryer/Mill System 2*	0.001	0.240	1.05
Dryer/Mill System 3*	0.001	0.240	1.05
Limestone and Infeed Silos	0.005	0.621	2.73
Subtotal		1.354	7.05
Ash Handling and Loadout			
Bed Ash Silos, Transport Systems, Fly Ash Silos, etc., Except as Below	0.001	0.428	1.88
Fly Ash Hoppers	0.005	0.026	0.12
Bed and Fly Ash Loadout	--	--	0.036
Subtotal		0.454	2.04
Total		--	12.84

* See also Table II

ATTACHMENT - ACID RAIN PERMIT

217-782-2113

ACID RAIN PROGRAM PERMIT

Indeck-Elwood Energy Center
Attn: Mr. Thomas M Campone, Designated Representative
600 North Buffalo Grove Road, Suite 300
Buffalo Grove, Illinois 60089

Oris No.: 55823
Illinois EPA I.D. No.: 197035AAJ
Source/Unit: Indeck-Elwood Energy Center, Unit 1 and 2
Date Received: May 13, 2002
Date Issued: October 10, 2003
Effective Date: January 1, 2006
Expiration Date: December 31, 2010

STATEMENT OF BASIS:

In accordance with Section 39.5(17)(b) of the Illinois Environmental Protection Act and Titles IV and V of the Clean Air Act, the Illinois Environmental Protection Agency is issuing this Acid Rain Program permit for the Indeck-Elwood Energy Center.

SULFUR DIOXIDE (SO_2) ALLOCATIONS AND NITROGEN OXIDE (NO_X) REQUIREMENTS FOR EACH AFFECTED UNIT:

Unit 1 and Unit 2	SO_2 Allowances	These Units are Not Entitled to an Allocation of SO_2 Allowances Pursuant to 40 CFR Part 73
	NO_x Emission Limitation	These Units are Not Subject to a NO_x Emissions Limitation Under 40 CFR Part 76.

This Acid Rain Program permit contains provisions related to sulfur dioxide (SO_2) emissions and requires the owners and operators to hold SO_2 allowances to account for SO_2 emissions beginning in the year 2000. An allowance is a limited authorization to emit up to one ton of SO_2 during or after a specified calendar year. Although this plant is not eligible for an allowance allocated by USEPA, the owners or operators may obtain SO_2 allowances to cover emissions from other sources under a marketable allowance program. The transfer of allowances to and from a unit account does not necessitate a revision to this permit (See 40 CFR 72.84).

This permit contains provisions related to nitrogen oxide (NO_x) emissions requiring the owners or operators to monitor NO_x emissions from affected units in accordance with the applicable provisions of 40 CFR Part 75.

This Acid Rain Program permit does not authorize the construction and operation of the affected units as such matters are addressed by Titles I and V of the Clean Air Act. If the construction and operation of one of the affected units is not undertaken, this permit shall not cover such unit.

In addition, notwithstanding the effective date of this permit as specified above, this permit shall not take effect for an individual affected unit until January 1 of the year in which the unit commences operation.

COMMENTS, NOTES AND JUSTIFICATIONS:

This permit does not affect the owners and operators responsibility to meet all other applicable local, state, and federal requirements, including requirements addressing SO_2 and NO_x emissions.

PERMIT APPLICATION:

The SO_2 allowance requirements and other standard requirements as set forth in the application are incorporated by reference into this permit. The owners and operators of this source must comply with the standard requirements and special provisions set forth in the application.

If you have any questions regarding this permit, please contact Mohamed Anane at 217/782-2113.

Donald E. Sutton, P.E.
Manager, Permits Section
Division of Air Pollution Control

DES:MA:jar

cc: Cecilia Mijares, USEPA Region V
Illinois EPA Region 1

ATTACHMENT – STANDARD PERMIT CONDITIONS

STANDARD CONDITIONS FOR CONSTRUCTION/DEVELOPMENT PERMITS
ISSUED BY THE ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

The Illinois Environmental Protection Act (Illinois Revised Statutes, Chapter 111-1/2, Section 1039) authorizes the Environmental Protection Agency to impose conditions on permits which it issues.

The following conditions are applicable unless superseded by special condition(s).

1. Unless this permit has been extended or it has been voided by a newly issued permit, this permit will expire one year from the date of issuance, unless a continuous program of construction or development on this project has started by such time.

2. The construction or development covered by this permit shall be done in compliance with applicable provisions of the Illinois Environmental Protection Act and Regulations adopted by the Illinois Pollution Control Board.

3. There shall be no deviations from the approved plans and specifications unless a written request for modification, along with plans and specifications as required, shall have been submitted to the Illinois EPA and a supplemental written permit issued.

4. The Permittee shall allow any duly authorized agent of the Illinois EPA upon the presentation of credentials, at reasonable times:

   a. To enter the Permittee’s property where actual or potential effluent, emission or noise sources are located or where any activity is to be conducted pursuant to this permit,

   b. To have access to and to copy any records required to be kept under the terms and conditions of this permit,

   c. To inspect, including during any hours of operation of equipment constructed or operated under this permit, such equipment and any equipment required to be kept, used, operated, calibrated and maintained under this permit,

   d. To obtain and remove samples of any discharge or emissions of pollutants, and

   e. To enter and utilize any photographic, recording, testing, monitoring or other equipment for the purpose of preserving, testing, monitoring, or recording any activity, discharge, or emission authorized by this permit.

5. The issuance of this permit:

   a. Shall not be considered as in any manner affecting the title of the premises upon which the permitted facilities are to be located,

   b. Does not release the Permittee from any liability for damage to person or property caused by or resulting from the construction, maintenance, or operation of the proposed facilities.

   c. Does not release the Permittee from compliance with other applicable statutes and regulations of the United States, of the State of Illinois, or with applicable local laws, ordinances and regulations.

   d. Does not take into consideration or attest to the structural stability of any units or parts of the project, and

   e. In no manner implies or suggests that the Illinois EPA (or its officers, agents or employees) assumes any liability, directly or indirectly, for any loss due to damage, installation, maintenance, or operation of the proposed equipment or facility.

6. a. Unless a joint construction/operation permit has been issued, a permit for operation shall be obtained from the Illinois EPA before the equipment covered by this permit is placed into operation.

   b. For purposes of shakedown and testing, unless otherwise specified by a special permit condition, the equipment covered under this permit may be operated for a period not to exceed thirty (30) days.

7. The Illinois EPA may file a complaint with the Board for modification, suspension or revocation of a permit.

   a. Upon discovery that the permit application contained misrepresentations, misinformation or false statement or that all relevant facts were not disclosed, or

   b. Upon finding that any standard or special conditions have been violated, or

   c. Upon any violations of the Environmental Protection Act or any regulation effective thereunder as a result of the construction or development authorized by this permit.

Commonwealth of Kentucky
Natural Resources and Environmental Protection Cabinet
Department for Environmental Protection
Division for Air Quality
803 Schenkel Lane
Frankfort, Kentucky 40601
(502) 573-3382

AIR QUALITY PERMIT

Permittee Name: East Kentucky Power Cooperative, Inc.
Mailing Address: P.O. Box 707, Winchester, Kentucky 40392-0707

is authorized to operate an
electric power generating plant at Maysville, Kentucky

Source Name: Hugh L. Spurlock Power Station
Mailing Address: P.O. Box 707, Winchester, Kentucky 40392-0707
Source Location: 1301 West Second Street

Permit Type: Federally-Enforceable
Review Type: Title V
Permit Number: V-97-050
Log Number: E917
Application Complete Date: February 11, 1997
KYEIS ID #: 103-2640-0009
AFS Plant ID #: 21-161-00009
FINDS Number: KYD072865272
SIC Code: 4911

Region: Huntington-Ashland
County: Mason

Issuance Date: **December 10, 1999**
Expiration Date: **December 10, 2004**

John E. Hornback, Director
Division for Air Quality

DEP7001 (1-97)

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SECTION A - PERMIT AUTHORIZATION

Pursuant to a duly submitted application which was determined to be complete on February 11, 1997, the Kentucky Division for Air Quality hereby authorizes the operation of the equipment described herein in accordance with the terms and conditions of this permit. This permit has been issued under the provisions of Kentucky Revised Statutes Chapter 224 and regulations promulgated pursuant thereto.

The permittee shall not construct, reconstruct, or modify any emission units without first having submitted a complete application and receiving a permit for the planned activity from the permitting authority, except as provided in this permit or in the Regulation 401 KAR 50:035, Permits.

Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits, licenses, or approvals required by this Cabinet or any other federal, state, or local agency.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

Emissions Unit 01 (01) - Indirect Heat Exchanger (Unit 1)

Description:

Pulverized coal-fired, dry-bottom, wall-fired unit equipped with electrostatic precipitator and low NO_x burners
Number two fuel oil used for startup and stabilization
Maximum continuous rating: 3500 mmBTU/hr
Construction commenced before: 1971

Applicable Regulations:

Regulation 401 KAR 61:015, Existing indirect heat exchangers applicable to an emission unit with a capacity more than 250 MMBTU per hour and commenced before August 17, 1971. Regulation 7, Prevention and control of emissions of particulate matter from combustion of fuel in indirect heat exchangers.

1. Operating Limitations:
None

2. Emission Limitations:

a) Pursuant to Regulation 401 KAR 61:015, Section 4 (4), and Regulation No. 7, particulate emissions shall not exceed 0.22 lb/MMBTU based on a three-hour average.

b) Pursuant to Regulation 401 KAR 61:015, Section 4 (4), Regulation No. 7, emissions shall not exceed 40 percent opacity based on a six-minute average except that a maximum of 60 percent opacity is allowed for a period or aggregate of periods not more than six minutes in any 60 minutes during building a new fire, cleaning the firebox, or blowing soot.

c) Pursuant to Regulation 401 KAR 61:015, Section 5 (1), sulfur dioxide emission shall not exceed 6.0 lbs/MMBTU based on a twenty-four-hour average.

3. Testing Requirements:

a) The permittee shall submit a schedule within six months from the issuance date of this permit to conduct at least one performance test for particulate within one year following the issuance of this permit.

b) If no additional stack tests are performed pursuant to Condition 4. d), the permittee shall conduct a performance test for particulate emissions within the third year of the term of this permit to demonstrate compliance with the applicable standard.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

c) The permittee shall determine the opacity of emissions from the stack by EPA Reference Method 9 annually, or more frequently if requested by the division.

4. Specific Monitoring Requirements:

a) Pursuant to Regulation 401 KAR 61:005, Section 3 and Regulation 401 KAR 50:035, Section 7(1)(c), continuous emission monitoring systems shall be installed, calibrated, maintained, and operated for measuring sulfur dioxide emissions and either oxygen or carbon dioxide emissions.The continuous emission monitoring systems shall comply with Regulation 401 KAR 61:005, Section 3, particularly, performance specification 2 of Appendix B to 40 CFR 60 or 40 CFR 75, Appendix A.

b) In accordance with Regulation 401 KAR 61:015, Section 6 (1), the sulfur content of solid fuels, as burned shall be determined in accordance with methods specified by the division.

c) In accordance with Regulation 401 KAR 61:015, Section 6 (3) the rate of each fuel burned shall be measured daily and recorded. The heating value and ash content of fuels shall be ascertained at least once per week and recorded. The average electrical output, and the minimum and maximum hourly generation rate shall be measured and recorded daily.

d) Pursuant to Regulation 401 KAR 50:035, Section 7(1)(c), to meet the periodic monitoring requirement for particulate, the permittee shall use a continuous opacity monitor (COM). Excluding the startup, shutdown, and once per hour exemption periods, if any six-minute average opacity value exceeds the opacity standard, the permittee shall, as appropriate, initiate an inspection of the control equipment and/or the COM system and make any necessary repairs. If five (5) percent or greater of COM data (excluding startup, shutdown, and malfunction periods, data averaged over six minute period) recorded in a calendar quarter show excursions above the opacity standard, the permittee shall perform a stack test in the following calendar quarter to demonstrate compliance with the particulate standard while operating at representative conditions. The permittee shall submit a compliance test protocol as required by condition Section G(a)(21) of this permit before conducting the test. The division may waive this testing requirement upon a demonstration that the cause(s) of the excursions have been corrected, or may require stack tests at any time pursuant to Regulation 401 KAR 50:045, Performance tests.

e) Pursuant to Regulation 401 KAR 50:035, Section 7(1)(c), to meet the periodic monitoring requirement for opacity, the permittee shall use a continuous opacity monitor (COM). Excluding the startup, shutdown, and once per hour exemption periods, if any six-minute average opacity value exceeds the opacity standard, the permittee shall, as appropriate, initiate an inspection of the control equipment and/or COM system and make any necessary repairs. If visible emissions from the stack are perceived or believed to exceed the applicable standard, the permittee shall determine the opacity of emissions by Reference Method 9. If a Method 9 cannot be performed, the reason for not performing the test shall be documented.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

f) Pursuant to Regulation 401 KAR 50:035, Section 7(1)(c), to meet the periodic monitoring requirement for sulfur dioxide, the permittee shall use a continuous emission monitor (CEM) Excluding the startup and shutdown periods, if any 24-hour average sulfur dioxide value exceeds the standard, the permittee shall, as appropriate, initiate an investigation of the cause of the exceedance and/or the CEM system and make any necessary repairs or take corrective actions as soon as practicable.

g) Pursuant to Regulation 401 KAR 61:005, Section 3, a continuous monitoring system for opacity shall conform to requirements of this section which include installing, calibrating, operating, and maintaining the continuous monitoring system for accurate opacity measurement, and demonstrating compliance with the applicable Performance Specification 1 of 40 CFR 60, Appendix B.

h) Pursuant to Regulation 401 KAR 61:005, Section 3(5), the division may provide a temporary exemption from the monitoring and reporting requirements of Regulation 401 KAR 61:005, Section 3, for the continuous monitoring system during any period of monitoring system malfunction, provided that the source owner or operator shows, to the division's satisfaction, that the malfunction was unavoidable and is being repaired as expeditiously as practicable.

5. Specific Record Keeping Requirements:

a) Records shall be kept in accordance with Regulations 401 KAR 61:005, Section 3(16) (f) and 61:015, Section 6, with the exception that the records shall be maintained for a period of five (5) years. Percentage of the COM data (excluding startup, shutdown, and malfunction data) showing excursions above the opacity standard in each calendar quarter shall be computed and recorded.

b) The permittee shall maintain the results of all compliance tests.

6. Specific Reporting Requirements:

a) Pursuant to Regulation 401 KAR 61:005, Section 3 (16), minimum data requirements which follow shall be maintained and furnished in the format specified by the division.

1. Owners or operators of facilities required to install continuous monitoring systems for opacity and sulfur dioxide or those utilizing fuel sampling and analysis for sulfur dioxide emissions shall submit for every calendar quarter, a written report of excess emissions and the nature and cause of the excess emissions if known. The averaging period used for data reporting should correspond to the emission standard averaging period which is a twenty-four (24) hour averaging period. All quarterly reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

2. For opacity measurements, the summary shall consist of the magnitude in actual percent opacity of six (6) minute averages of opacity greater than the opacity standard in the applicable standard for each hour of operation of the facility. Average values may be obtained by integration over the averaging period or by arithmetically averaging a minimum of four (4) equally spaced, instantaneous opacity measurements per minute. Any time period exempted shall be considered before determining the excess average of opacity.

3. For gaseous measurements the summary shall consist of hourly averages in the units of the applicable standard.

4. The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of system repairs or adjustments shall be reported. Proof of continuous monitoring system performance is required as specified by the division whenever system repairs or adjustments have been made.

5. When no excess emissions have occurred and the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be included in the report.

b) The permittee shall report the number of excursions (excluding startup, shutdown, malfunction data) above the opacity standard, date and time of excursions, opacity value of the excursions, and percentage of the COM data showing excursions above the opacity standard in each calendar quarter.

7. <u>Specific Control Equipment Operating Conditions:</u>

a) The electrostatic precipitator shall be operated as necessary to maintain compliance with permitted emission limitations, in accordance with manufacturer's specifications and/or good operating practices.

b) Records regarding the maintenance of the electrostatic precipitator shall be maintained.

c) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

Emissions Unit 02 (02) - Indirect Heat Exchanger (Unit 2)

Description:
Pulverized coal-fired, dry-bottom, tangientally fired unit equipped with electrostatic precipitator, low NO_x burners and flue gas desulfurization (FGD) system
Number two fuel oil used for startup and stabilization
Maximum continuous rating: 4850 mmBTU/hr
Construction commenced: 1981

Applicable Regulations:

Regulation 401 KAR 59:015, New indirect heat exchangers, incorporating by reference 40 CFR 60, Subpart D, Standards of performance for fossil-fuel-fired steam generators applicable to an emissions unit more than 250 MMBTU/hour and commenced after August 17, 1971

1. Operating Limitations:
None

2. Emission Limitations:

a) Pursuant to Regulation 401 KAR 59:015, Section 4 (1)(b), particulate emissions shall not exceed 0.1 lb/MMBTU based on a three-hour average.

b) Pursuant to Regulation 401 KAR 59:015, Section 4 (2), emissions shall not exceed twenty (20) percent opacity based on a six-minute average except a maximum of twenty-seven (27) percent opacity for not more than one (1) six (6) minutes period in any sixty (60) consecutive minutes.

c) Pursuant to Regulation 401 KAR 59:015, Section 5 (1)(b), sulfur dioxide emission shall not exceed 1.2 lbs/MMBTU based on a three-hour average.

d) Pursuant to Regulation 401 KAR 59:015, Section 6(1)(c), nitrogen oxides emission shall not exceed 0.70 lb/MMBTU based on a three-hour average.

3. Testing Requirements:

a) The permittee shall submit a schedule within six months from the issuance date of this permit to conduct at least one performance test for particulate within one year following the issuance of this permit.

b) If no additional stack tests are performed pursuant to Condition 4. d), the permittee shall conduct a performance test for particulate emissions within the third year of the term of this permit to demonstrate compliance with the applicable standard.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

c) The permittee shall determine the opacity of emissions from the stack by EPA Reference Method 9 annually, or more frequently if requested by the division.

4. Specific Monitoring Requirements:

a) Pursuant to Regulation 401 KAR 50:035, Section 7(1)(c), Regulation 401 KAR 59:015, Section 7, and Regulation 401 KAR 59:005, Section 4, continuous emission monitoring systems shall be installed, calibrated, maintained, and operated for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions and either oxygen or carbon dioxide emissions. The owner or operator shall ensure the continuous emission monitoring systems are in compliance with, and the owner or operator shall comply with the requirements of Regulation 401 KAR 59:005, Section 4.

b) Pursuant to Regulation 401 KAR 50:035, Section 7(1)(c), to meet the periodic monitoring requirement for particulate, the permittee shall use a continuous opacity monitor (COM). Excluding the startup, shutdown, and once per hour exemption periods, if any six minute average opacity value exceeds the opacity standard, the permittee shall, as appropriate, initiate an inspection of the control equipment and/or the COM system and make any necessary repairs. If five (5) percent or greater of COM data (excluding startup, shutdown, and malfunction periods, data averaged over six minute period) recorded in a calendar quarter show excursions above the opacity standard, the permittee shall perform a stack test in the following calendar quarter to demonstrate compliance with the particulate standard while operating at representative conditions. The permittee shall submit a compliance test protocol as required by condition Section G(a)(21) of this permit before conducting the test. The division may waive this testing requirement upon a demonstration that the cause(s) of the excursions have been corrected, or may require stack tests at any time pursuant to Regulation 401 KAR 50:045, Performance tests.

c) Pursuant to Regulation 401 KAR 50:035, Section 7(1)(c), to meet the periodic monitoring requirement for opacity, the permittee shall use a continuous opacity monitor (COM). Excluding the startup, shutdown, and once per hour exemption periods, if any six minute average opacity value exceeds the opacity standard, the permittee shall, as appropriate, initiate an inspection of the control equipment and/or the COM system and make any necessary repairs. If visible emissions from the stack are perceived or believed to exceed the applicable standard, the permittee shall determine the opacity of emissions by Reference Method 9. If a Method 9 test cannot be performed, the reason for not performing the test shall be documented.

d) Pursuant to Regulation 401 KAR 50:035, Section 7(1)(c), to meet the periodic monitoring requirement for sulfur dioxide, the permittee shall use a continuous emission monitor (CEM) Excluding the startup and shutdown periods, if any 3-hour average sulfur dioxide value exceeds the standard, the permittee shall, as appropriate, initiate an investigation of the cause of the exceedance and/or the CEM system and make any necessary repairs or take corrective actions as soon as practicable.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

e) Pursuant to Regulation 401 KAR 50:035, Section 7(1)(c), to meet the periodic monitoring requirement for nitrogen oxide, the permittee shall use a continuous emission monitor (CEM).Excluding the startup and shutdown periods, if any 3-hour average nitrogen oxide value exceeds the standard, the permittee shall, as appropriate, initiate an investigation of the cause of the exceedance and/or the CEM system and make any necessary repairs or take corrective actions as soon as practicable.

f) Pursuant to Regulation 401 KAR 59:015, Section 7(3), for performance evaluations of the sulfur dioxide and nitrogen oxides continuous emission monitoring system as required under Regulation 401 KAR 59:005, Section 4(3) and calibration checks as required under Regulation 401 KAR 59:005, Section 4(4), Reference Methods 6 or 7 shall be used as applicable as described by Regulation 401 KAR 50:015.

g) Pursuant to Regulation 401 KAR 59:015, Section 7(3), sulfur dioxide or nitric oxides (nitrogen oxides), as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B to 40 CFR 60, filed by reference in Regulation 401 KAR 50:015.

h) Pursuant to Regulation 401 KAR 59:015, Section 7(3), the span value of all continuous emission monitoring system measuring opacity of emissions shall be eighty (80), ninety (90), or one-hundred (100) percent and the span value for the continuous emission monitoring system measuring sulfur dioxide and nitrogen oxides emissions shall be in accordance with Regulation 401 KAR 59:015, Appendix C or 40 CFR 75, Appendix A.

i) Continuous emission monitoring data shall be converted into the units of applicable standards using the conversion procedure described in Regulation 401 KAR 59:015, Section 7(5).

j) Pursuant to Regulation 401 KAR 59:015, Section 7(3), for an indirect heat exchanger that simultaneously burns fossil fuel and nonfossil fuel, the span value of all continuous monitoring systems shall be subject to the division's approval.

5. Specific Record Keeping Requirements:

a) Pursuant to Regulation 401 KAR 59:005, Section 3 (4), the owner or operator of the indirect heat exchanger shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems and devices; and all other information required by Regulation 401 KAR 59:005 recorded in a permanent form suitable for inspection.

b) Pursuant to Regulation 401 KAR 59:005, Section 3(2), the owner or operator of this unit shall maintain the records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility, any malfunction of the air pollution control equipment; or any period during which a continuous monitoring system or monitoring device is inoperative.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

c) The permittee shall compute and record percentage of the COM data (excluding startup, shutdown, and malfunction data) showing excursions above the opacity standard in each calendar quarter.

d) The permittee shall maintain the results of all compliance tests.

6. Specific Reporting Requirements:

a) Pursuant to Regulation 401 KAR 59:005, Section 3 (3), minimum data requirements which follow shall be maintained and furnished in the format specified by the division. Owners or operators of facilities required to install continuous monitoring systems shall submit for every calendar quarter a written report of excess emissions (as defined in applicable sections) to the division. All quarterly reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter and shall include the following information:

1) The magnitude of the excess emission computed in accordance with the Regulation 401 KAR 59:005, Section 4(8), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

2) All hourly averages shall be reported for sulfur dioxide and nitrogen oxides monitors. The hourly averages shall be made available in the format specified by the division.

3) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventive measures adopted.

4) The date and time identifying each period during which continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

5) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

b) Pursuant to Regulation 401 KAR 59:015, Section 7(7), for the purposes of reports required under Regulation 401 KAR 59:005, Section 3(3), periods of excess emissions that shall be reported are defined as follows:

1) Excess emissions are defined as any six minute period during which the average opacity of emissions exceeds twenty percent opacity, except that one (1) six (6) minute average per hour of up to twenty-seven (27) percent opacity need not be reported.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

2) Excess emissions of sulfur dioxide is defined as any three (3) hour period during which the average emissions (arithmetic average of three contiguous one hour periods) exceed the applicable sulfur dioxide emissions standards.

3) Excess emissions for emissions units using a continuous monitoring system for measuring nitrogen oxides are defined as any three (3) hour period during which the average emissions (arithmetic average of three contiguous one hour periods) exceed the applicable nitrogen oxides emissions standards.

c) The permittee shall report the number of excursions (excluding startup, shutdown, malfunction data) above the opacity standard, date and time of excursions, opacity value of the excursions, and percentage of the COM data showing excursions above the opacity standard in each calendar quarter.

7. Specific Control Equipment Operating Conditions:

a) The electrostatic precipitator (ESP), flue gas desulfurization unit (FGD), and the low NO_x burner shall be operated as necessary to maintain compliance with permitted emission limitations, consistence with manufacturer's specifications and / or good operating practices.

b) Records regarding the maintenance of the control equipments shall be maintained.

c) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

Emissions Unit 03 (03) - Indirect Heat Exchanger (Auxiliary Boiler)

Description:

Number two fuel oil-fired
Maximum continuous rating: 144 mmBTU/hr
Construction commenced: 1971

Applicable Regulations:

Regulations 401 KAR 61:015, Existing indirect heat exchangers, commenced before August 17, 1971, and Regulation 7, Prevention and Control of Emissions of Particulate Matter from Combustion of Fuel in Indirect Heat Exchangers

1. Operating Limitations:

None

2. Emission Limitations:

a) Pursuant to Regulation 401 KAR 61:015, Section 4 (4), and Regulation No. 7, particulate emissions shall not exceed 0.22 lb/MMBtu based on a three-hour average.

b) Pursuant to Regulation 401 KAR 61:015, Section 4 (4), and Regulation No. 7, emissions shall not exceed 40 percent opacity based on a six-minute average except that a maximum of 60 percent opacity is allowed for a period or aggregate of periods not more than six minutes in any sixty minutes during building a new fire, cleaning the firebox, or blowing soot.

c) Pursuant to Regulation 401 KAR 61:015, Section 5 (1), sulfur dioxide emissions shall not exceed 4.0 lb/MMBtu based on a twenty-four-hour average

3. Testing Requirements:

When the unit is in operation, the permittee shall read, weather permitting, the opacity of the emissions from the stack using EPA Reference Method 9 once per day.

4. Specific Monitoring Requirements:

a) Pursuant to Regulation 401 KAR 61:015, Section 6 (2), the sulfur content of liquid fuels, as burned, shall be determined based on certification from the fuel supplier. This certification shall include the name of the oil supplier and a statement that the oil complies with the specifications under the definition for distillate oil in Regulation 401 KAR 60:043.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

b) In accordance with Regulation 401 KAR 61:015, Section 6 (3), the rate of fuel burned shall be measured daily on an as-burned basis and recorded while the boiler is in operation.

5. Specific Record Keeping Requirements:

a) Records documenting the amount of fuel oil consumed shall be maintained.

b) Records documenting the sulfur content and heating value of the fuel oil shall be maintained.

c) The permittee shall keep the results of all compliance tests.

6. Specific Reporting Requirements:

a) See Section F.

7. Specific Control Equipment Operating Conditions:

NA

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

Emissions Unit 04 (05, 06, 10, 11, 12) - Coal Handling Operations

Description:

Reclaim hoppers onto coal conveyor, crusher house, and conveyor drop points.

Operating rate: 4000 tons/hr
Construction commenced : 1981

Applicable Regulations:

Regulation 401 KAR 60:005, Standards of performance for new stationary sources, which incorporates by reference 40 CFR 60.250 (40 CFR 60, Subpart Y), applies to conveyors and crushers which process more than 200 tons of coal per day and commenced after October 24, 1974 .

1. Operating Limitations:

None

2. Emission Limitations:

Pursuant to Regulation 401 KAR 60:005, 40 CFR 60.252, the owner or operator subject to the provisions of this regulation shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or transfer and loading system processing coal, emissions which exhibit 20 percent opacity or greater.

3. Testing Requirements:

Pursuant to Regulation 401 KAR 60:005, 40 CFR 60.254, EPA Reference Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity quarterly.

4. Specific Monitoring Requirements:

The permittee shall perform a qualitative visual observation of the opacity of emissions from each stack on a weekly basis and maintained a log of the observation. If visible emissions from any stack are perceived or believed to exceed the applicable standard, the permittee shall determined the opacity of emissions by Reference Method 9 and instigate an inspection of the control equipment for any necessary repairs.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

5. Specific Record Keeping Requirements:

a) The permittee shall maintain the records of amount of coal received and processed.

b)The permittee shall maintain the result of all compliance tests.

6. Specific Reporting Requirements:

See Section F.

7. Specific Control Equipment Operating Conditions:

a) The control equipment enclosures, wet suppression, and baghouses used to control particulate emissions shall be operated as necessary to maintain compliance with applicable requirements, in accordance with manufacturer's specifications and / or standard operating practices.

b) Records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

Emissions Unit 07 (04, 07, 08, 09) - Coal Handling Operations

Description:

Transfer tower # 1 & 2, rotary railcar unloader, barge unloader, sampling tower, radial stacker, coal stockpiles, haul roads, and yard area.

Operating rate: 4600 tons/hr
Construction commenced prior to: 1970

Applicable Regulations:

Regulation 401 KAR 63:010, Fugitive emissions

Applicable Requirements:

a) Pursuant to Regulation 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not be limited to the following:

1. Application and maintenance of asphalt, water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dusts;

2. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling;

b) Pursuant to Regulation 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

1. Operating Limitations:

None

2. Emission Limitations:

None

3. Testing Requirements:

None

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

4. Specific Monitoring Requirements:

The permittee shall monitor the amount of coal received and processed.

5. Specific Record Keeping Requirements:

The permittee shall maintain records of amount of coal received and processed.

6. Specific Reporting Requirements:

See Section F, Conditions 5,6,7, and 8.

7. Specific Control Equipment Operating Conditions:

a) The control equipment (including but not limited to hoods, enclosures, use of dust suppressant/foam, telescopic chute, and wet suppression) shall be operated as necessary to maintain compliance with applicable requirements, in accordance with manufacturer's specifications and / or standard operating practices.

b) Records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

SECTION C - INSIGNIFICANT ACTIVITIES

The following listed activities have been determined to be insignificant activities for this source pursuant to Regulation 401 KAR 50:035, Section 5(4). While these activities are designated as insignificant the permittee must comply with the applicable regulation(s). Process and emission control equipment at each insignificant activity subject to a generally applicable regulation shall be inspected weekly and a qualitative visible emissions evaluation made. The results of the inspections and observations shall be recorded in a log, noting color, duration, density (heavy or light), cause and any corrective actions taken for any abnormal visible emissions.

	Description	Generally Applicable Regulation
1.	Storage vessels containing petroleum or organic liquids with a capacity of less than 10,567 gallons, providing (a) the vapor pressure of the stored liquid is less than 1.5 psia at storage temperature, or (b) vessels greater than 580 gallons with stored liquids having greater than 1.5 psia vapor pressure are equipped with a permanent submerged fill pipe.	NA
2.	Storage vessels containing inorganic aqueous liquids, except inorganic acids with boiling points below the maximum storage temperature at atmospheric pressure.	NA
3.	#2 oil-fired space heaters or ovens rated at less than two million BTU per hour actual heat input, provided the maximum sulfur content is less than 0.5% by weight.	NA
4.	Machining of metals, providing total solvent usage at the source for this activity does not exceed 60 gallons per month.	NA
5.	Internal combustion engines using only gasoline, diesel fuel, natural gas, or LP gas rated at 50 hp or less.	NA
6.	Volatile organic compound and hazardous air pollutant storage containers, as follows: (a) Tanks, less than 1,000 gallons, and throughput less than 12,000 gallons per year; (b) Lubricating oils, hydraulic oils, machining oils, and machining fluids.	NA

SECTION C - INSIGNIFICANT ACTIVITIES (Continued)

	Description	Generally Applicable Regulation
7.	Machining where an aqueous cutting coolant continuously floods machining interface.	NA
8.	Degreasing operations, using less than 145 gallons per year.	NA
9.	Maintenance equipment, not emitting HAPs: brazing, cutting torches, soldering, welding.	NA
10.	Underground conveyors.	NA
11.	Coal bunker and coal scale exhausts.	401 KAR 63:010
12.	Blowdown (sight glass, boiler, compressor, pump, cooling tower).	NA
13.	Stationary fire pumps.	NA
14.	Grinding and machining operations vented through fabric filters, scrubbers, mist eliminators, or electrostatic precipitators (e.g., deburring, buffing, polishing, abrasive blasting, pneumatic conveying, woodworking).	401 KAR 63:010
15.	Vents from ash transport systems not operated at positive pressure.	401 KAR 63:010
16.	Wastewater treatment (for stream less than 1% oil and grease).	NA
17.	Heat exchanger cleaning and repair.	NA
18.	Repair and maintenance of ESP, fabric filters, etc.	NA
19.	Any operation using aqueous solution (less than 1% VOC).	NA
20.	Laboratory fume hoods and vents used exclusively for chemical or physical analysis, or for “bench scale production” R&D facilities.	NA

SECTION C - INSIGNIFICANT ACTIVITIES (Continued)

	Description	Generally Applicable Regulation
21.	Machinery lubricant and waxes, including oils, greases or other lubricants applied as temporary protective coatings.	NA
22.	Purging of gas lines and vessels related to routine maintenance.	NA
23.	Flue gas conditioning systems.	NA
24.	Equipment used to collect spills.	NA
25.	Ash pond and ash pond maintenance.	NA
26.	Emergency generators: gasoline-powered (<110 hp), diesel-powered (<1600 hp).	NA
27.	Lime handling system; including truck unloading (for scrubber lime and stabilization lime), and lime feed systems.	401 KAR 63:010
28.	Fly ash storage silos (both loading and unloading).	401 KAR 63:010
29.	Off-specification used oil fuel burned for energy recovery	NA
30.	Bottom ash screening and sizing system.	401 KAR 63:010
31.	Railcar/truck flyash loadout.	401 KAR 63:010

SECTION D - SOURCE EMISSION LIMITATIONS AND TESTING REQUIREMENTS

Particulate, sulfur dioxide, nitrogen oxide, and visible (opacity) emissions, as measured by methods referenced in Regulation 401 KAR 50:015, Section 1, shall not exceed the respective limitations specified herein.

SECTION E - CONTROL EQUIPMENT CONDITIONS

Pursuant to Regulation 401 KAR 50:055, Section 2(5), at all times, including periods of startup, shutdown and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the division which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

SECTION F - MONITORING, RECORD KEEPING, AND REPORTING REQUIREMENTS

1. When continuing compliance is demonstrated by periodic testing or instrumental monitoring, the permittee shall compile records of required monitoring information that include:
   a. Date, place as defined in this permit, and time of sampling or measurements.
   b. Analyses performance dates;
   c. Company or entity that performed analyses;
   d. Analytical techniques or methods used;
   e. Analyses results; and
   f. Operating conditions during time of sampling or measurement;

2. Records of all required monitoring data and support information, including calibrations, maintenance records, and original strip chart recordings, and copies of all reports required by the Division for Air Quality, shall be retained by the permittee for a period of five years and shall be made available for inspection upon request by any duly authorized representative of the Division for Air Quality. [401 KAR 50:035, Permits, Section 7(1)(d)2 and 401 KAR 50:035, Permits, Section 7(2)(c)]

3. In accordance with the requirements of Regulation 401 KAR 50:035, Permits, Section 7(2)(c) the permittee shall allow the Cabinet or authorized representatives to perform the following:
   a. Enter upon the premises where a source is located or emissions-related activity is conducted, or where records are kept;
   b. Have access to and copy, at reasonable times, any records required by the permit:
      i. During normal office hours, and
      ii. During periods of emergency when prompt access to records is essential to proper assessment by the Cabinet;
   c. Inspect, at reasonable times, any facilities, equipment (including monitoring and pollution control equipment), practices, or operations required by the permit. Reasonable times shall include, but are not limited to the following:
      i. During all hours of operation at the source,
      ii. For all sources operated intermittently, during all hours of operation at the source and the hours between 8:00 a.m. and 4:30 p.m., Monday through Friday, excluding holidays, and
      iii. During an emergency; and
   d. Sample or monitor, at reasonable times, substances or parameters to assure compliance with the permit or any applicable requirements. Reasonable times shall include, but are not limited to the following:
      i. During all hours of operation at the source,
      ii. For all sources operated intermittently, during all hours of operation at the source and the hours between 8:00 a.m. and 4:30 p.m., Monday through Friday, excluding holidays, and
      iii. During an emergency.

SECTION F - MONITORING, RECORD KEEPING, AND REPORTING REQUIREMENTS (CONTINUED)

4. No person shall obstruct, hamper, or interfere with any Cabinet employee or authorized representative while in the process of carrying out official duties. Refusal of entry or access may constitute grounds for permit revocation and assessment of civil penalties.

5. Summary reports of any monitoring required by this permit, other than continuous emission or opacity monitors, shall be submitted to the Division's Florence Regional Office at least every six (6) months during the life of this permit, unless otherwise stated in this permit. The reports are due within 30 days after the end of each six month reporting period which commences on the initial issuance date of this permit. The permittee may shift to semi-annual reporting on a calendar year basis upon approval of the regional office. If calendar year reporting is approved, the semi-annual reports are due January 30th and July 30th of each year. Data from the continuous emission and opacity monitors shall be reported to the Technical Services Branch in accordance with the requirements of Regulation 401 KAR 59:005, General Provisions, Section 3(3). All reports shall be certified by a responsible official pursuant to Section 6(1) of Regulation 401 KAR 50:035, Permits. All deviations from permit requirements shall be clearly identified in the reports.

6. a. In accordance with the provisions of Regulation 401 KAR 50:055, Section 1 the owner or operator shall notify the Division for Air Quality's Ashland Regional Office concerning startups, shutdowns, or malfunctions as follows:
    1. When emissions during any planned shutdowns and ensuing startups will exceed the standards notification shall be made no later than three (3) days before the planned shutdown, or immediately following the decision to shutdown, if the shutdown is due to events which could not have been foreseen three (3) days before the shutdown.
    2. When emissions due to malfunctions, unplanned shutdowns and ensuing startups are or may be in excess of the standards notification shall be made as promptly as possible by telephone (or other electronic media) and shall cause written notice upon request.

   b. In accordance with the provisions of Regulation 401 KAR 50:035, Section 7(1)(e)2, the owner or operator shall promptly report deviations from permit requirements including those attributed to upset conditions to the Division for Air Quality's Ashland Regional Office. Prompt reporting shall be defined as quarterly for any deviation related to emission standards (other than emission exceeding covered by general condition 6(a) above) and semi-annually for all other deviations from the permit requirements if not otherwise specified in the permit.

7. Pursuant to Regulation 401 KAR 50:035, Permits, Section 7(2)(b), the permittee shall certify compliance with the terms and conditions contained in this permit, annually on the permit issuance anniversary date or by January 30th of each year if calendar year reporting is approved by the regional office, by completing and returning a Compliance Certification Form (DEP 7007CC) (or an approved alternative) to the Division for Air Quality's Ashland Regional Office and the U.S. EPA in accordance with the following requirements:
   a. Identification of each term or condition of the permit that is the basis of the certification;

SECTION F - MONITORING, RECORD KEEPING, AND REPORTING REQUIREMENTS (CONTINUED)

b. The compliance status regarding each term or condition of the permit;
c. Whether compliance was continuous or intermittent; and

d. The method used for determining the compliance status for the source, currently and over the reporting period, pursuant to 401 KAR 50:035, Section 7(1)(c),(d), and (e).

e. The certification shall be postmarked by the thirtieth (30) day following the applicable permit issuance anniversary date, or by January 30th of each year if calendar year reporting is approved by the regional office. Annual compliance certifications should be mailed to the following addresses**:**

Division for Air Quality
Ashland Regional Office
P.O. Box 1507
Ashland, Kentucky 41105-1507

U.S. EPA Region IV
Air Enforcement Branch
Atlanta Federal Center
61 Forsyth St.
Atlanta, GA 30303-8960

Division for Air Quality
Central Files
803 Schenkel Lane
Frankfort, KY 40601

8. In accordance with Regulation 401 KAR 50:035, Section 23, the permittee shall provide the division with all information necessary to determine its subject emissions within thirty (30) days of the date the KEIS emission report is mailed to the permittee.

9. Pursuant to Section VII.3 of the policy manual of the Division for Air Quality as referenced by Regulation 401 KAR 50:016, Section 1(1), results of performance test(s) required by the permit shall be submitted to the division by the source or its representative within forty-five days after the completion of the fieldwork.

SECTION G - GENERAL CONDITIONS

(a) General Compliance Requirements

1. The permittee shall comply with all conditions of this permit. A noncompliance shall be (a) violation(s) of state regulation 401 KAR 50:035, Permits, Section 7(3)(d) and for federally enforceable permits is also a violation of Federal Statute 42 USC 7401 through 7671q (the Clean Air Act**)** and is grounds for enforcement action including but not limited to the termination, revocation and reissuance, or revision of this permit.

2. The filing of a request by the permittee for any permit revision, revocation, reissuance, or termination, or of a notification of a planned change or anticipated noncompliance, shall not stay any permit condition.

3. This permit may be revised, revoked, reopened and reissued, or terminated for cause. The permit will be reopened for cause and revised accordingly under the following circumstances:
   a. If additional applicable requirements become applicable to the source and the remaining permit term is three (3) years or longer. In this case, the reopening shall be completed no later than eighteen (18) months after promulgation of the applicable requirement. A reopening shall not be required if compliance with the applicable requirement is not required until after the date on which the permit is due to expire, unless this permit or any of its terms and conditions have been extended pursuant to Regulation 401 KAR 50:035, Section 12(2)(c);
   b. The Cabinet or the U. S. EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements;
   c. The Cabinet or the U. S. EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit;
   d. If any additional applicable requirements of the Acid Rain Program become applicable to the source.

   Proceedings to reopen and reissue a permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists. Reopenings shall be made as expeditiously as practicable. Reopenings shall not be initiated before a notice of intent to reopen is provided to the source by the division, at least thirty (30) days in advance of the date the permit is to be reopened, except that the division may provide a shorter time period in the case of an emergency.

4. The permittee shall furnish to the division, in writing, information that the division may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. [401 KAR 50:035, Permits, Section 7(2)(b)3e and 401 KAR 50:035, Permits, Section 7(3)(j)]

5. The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such supplementary facts or corrected information to the permitting authority.

SECTION G - GENERAL CONDITIONS (CONTINUED)

6. Any condition or portion of this permit which becomes suspended or is ruled invalid as a result of any legal or other action shall not invalidate any other portion or condition of this permit. [401 KAR 50:035, Permits, Section 7(3)(k)]

7. The permittee shall not use as a defense in an enforcement action the contention that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance. [401 KAR 50:035, Permits, Section 7(3)(e)]

8. Except as identified as state-origin requirements in this permit, all terms and conditions contained herein shall be enforceable by the United States Environmental Protection Agency and citizens of the United States.

9. This permit shall be subject to suspension if the permittee fails to pay all emissions fees within 90 days after the date of notice as specified in 401 KAR 50:038, Section 3(6). [401 KAR 50:035, Permits, Section 7(3)(h)]

10. Nothing in this permit shall alter or affect the liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance. [401 KAR 50:035, Permits, Section 8(3)(b)]

11. This permit shall not convey property rights or exclusive privileges. [401 KAR 50:035, Permits, Section 7 (3)(g)]

12. Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits, licenses, or approvals required by the Kentucky Cabinet for Natural Resources and Environmental Protection or any other federal, state, or local agency.

13. Nothing in this permit shall alter or affect the authority of U.S. EPA to obtain information pursuant to Federal Statute 42 USC 7414, Inspections, monitoring, and entry. [401 KAR 50:035 , Permits, Section 7(2)(b)5]

14. Nothing in this permit shall alter or affect the authority of U.S. EPA to impose emergency orders pursuant to Federal Statute 42 USC 7603, Emergency orders. [401 KAR 50:035, Permits, Section 8(3)(a)]

15 Permit Shield: Except as provided in State Regulation 401 KAR 50:035, Permits, compliance by the emissions units listed herein with the conditions of this permit shall be deemed to be compliance with all applicable requirements identified in this permit as of the date of issuance of this permit.

16. All previously issued construction and operating permits are hereby subsumed into this permit.

SECTION G - GENERAL CONDITIONS (CONTINUED)

17. The permittee may conduct test burns of materials other than those listed in the permit without a construction permit or a reopening of this permit provided that:

    a) Notification is provided to the division at least 30 days prior to initiation of the test burning of the material;
    b) The source complies with all applicable regulations and emission limitations;
    c) The permittee agrees to perform such additional testing as may be required by the division;

18. The permanent burning of any materials (addressed in above condition) shall be allowed upon completion of testing provided that:

    a) The division determines that a permit is not required. Such determination shall be made within sixty (60) days of the application receipt along with the test result;
    b) The permittee keep records of date and time of burn;
    c) The permittee keeps records of analysis and feed rate of material;
    b) Burning any of those materials shall not be subject to any applicable regulation and the source shall comply with all applicable regulation and emission limitations.

19. Fugitive emissions shall be controlled in accordance with Regulation 401 KAR 63:010.

20. Emission limitations listed in this permit shall apply at all times except during periods of startup, shutdown, or malfunctions, and opacity limitations listed in this permit shall apply at all times except during periods of startup and shutdown in accordance with Regulation 401 KAR 50:055, provided the permittee complies with the requirements of Regulation 401 KAR 50:055.

21. Pursuant to Section VII 2.(1) of the policy manual of the Division for Air Quality as referenced by regulation 401 KAR 50:016, Section 1(1), at least one month prior to the date of the required performance test, the permittee shall complete and return a Compliance Test Protocol(Form DEP 6027) to the division's Frankfort Central Office. Pursuant to Regulation 401 KAR 50:045, Section 5, the division shall be notified of the actual test date at least ten (10) days prior the test.

(b) Permit Expiration and Reapplication Requirements

This permit shall remain in effect for a fixed term of five (5) years following the original date of issue. Permit expiration shall terminate the source's right to operate unless a timely and complete renewal application has been submitted to the division at least six months prior to the expiration date of the permit. Upon a timely and complete submittal, the authorization to operate within the terms and conditions of this permit, including any permit shield, shall remain in effect beyond the expiration date, until the renewal permit is issued or denied by the Division. [401 KAR 50:035, Permits, Section 12]

SECTION G - GENERAL CONDITIONS (CONTINUED)

(c) Permit Revisions

1. A minor permit revision procedure may be used for permit revisions involving the use of economic incentive, marketable permit, emission trading, and other similar approaches, to the extent that these minor permit revision procedures are explicitly provided for in the SIP or in applicable requirements and meet the relevant requirements of Regulation 401 KAR 50:035, Section 15.

2. This permit is not transferable by the permittee. Future owners and operators shall obtain a new permit from the Division for Air Quality. The new permit may be processed as an administrative amendment if no other change in this permit is necessary, and provided that a written agreement containing a specific date for transfer of permit responsibility coverage and liability between the current and new permittee has been submitted to the permitting authority thirty (30) days in advance of the transfer.

(d) Acid Rain Program Requirements

1. If an applicable requirement of Federal Statute 42 USC 7401 through 7671q (the Clean Air Act) is more stringent than an applicable requirement promulgated pursuant to Federal Statute 42 USC 7651 through 7651o (Title IV of the Act), both provisions shall apply, and both shall be state and federally enforceable.

2. The source shall comply with all requirements and conditions of the Title IV Acid Rain Permit (A-98-010, Attachment C) and the Phase II permit application (including the Phase II NO_x compliance plan and averaging plan, if applicable) issued for this source. The source shall also comply with all requirements of any revised or future acid rain permit(s) issued to this source.

(e) Emergency Provisions

1. An emergency shall constitute an affirmative defense to an action brought for noncompliance with the technology-based emission limitations if the permittee demonstrates through properly signed contemporaneous operating logs or other relevant evidence that:

   a. An emergency occurred and the permittee can identify the cause of the emergency;
   b. The permitted facility was at the time being properly operated;
   c. During an emergency, the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards or other requirements in the permit; and,
   d. The permittee notified the division as promptly as possible and submitted written notice of the emergency to the division within two working days after the time when emission limitations were exceeded due to the emergency. The notice shall meet the requirements of 401 KAR 50:035, Permits, Section 7(1)(e)2, and include a description of the emergency, steps taken to mitigate emissions, and the corrective actions taken.This requirement does not relieve the source of any other local, state or federal notification requirements.

SECTION G - GENERAL CONDITIONS (CONTINUED)

2. Emergency conditions listed in General Condition (f)1 above are in addition to any emergency or upset provision(s) contained in an applicable requirement.

3. In an enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [401 KAR 50:035, Permits, Section 9(3)]

(f). Risk Management Provisions

1. The permittee shall comply with all applicable requirements of 40 CFR Part 68, Risk Management Plan provisions. If required, the permittee shall comply with the Risk Management program and submit a Risk Management Plan to:
RMP Reporting Center
P.O. Box 3346
Merrifield, VA, 22116-3346

(g). Ozone Depleting Substances

1. The permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR 82, Subpart F, except as provided for Motor Vehicle Air Conditioners (MVACs) in Subpart B:

   a. Persons opening appliances for maintenance, service, repair, or disposal shall comply with the required practices contained in 40 CFR 82.156.
   b. Equipment used during the maintenance, service, repair, or disposal of appliances shall comply with the standards for recycling and recovery equipment contained in 40 CFR 82.158.
   c. Persons performing maintenance, service, repair, or disposal of appliances shall be certified by an approved technician certification program pursuant to 40 CFR 82.161.
   d. Persons disposing of small appliances, MVACs, and MVAC-like appliances (as defined at 40 CFR 82.152) shall comply with the recordkeeping requirements pursuant to 40 CFR 82.166.
   e. Persons owning commercial or industrial process refrigeration equipment shall comply with the leak repair requirements pursuant to 40 CFR 82.156.
   f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant shall keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR 82.166.

2. If the permittee performs service on motor (fleet) vehicle air conditioners containing ozone-depleting substances, the source shall comply with all applicable requirements as specified in 40 CFR 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

SECTION H - ALTERNATE OPERATING SCENARIOS

None

SECTION I - COMPLIANCE SCHEDULE

None

MONTANA AIR QUALITY PERMIT

Issued To: Southern Montana Electric
Generation and Transmission Cooperative –
Highwood Generating Station
3521 Gabel Road, Suite 5
Billings, MT 59102

Permit: #3423-00
Application Complete: 5/16/06
Preliminary Determination Issued: 3/30/06
Supplemental Preliminary Determination
Issued: 6/22/06
Department's Decision Issued:
Permit Final:
AFS #: 030-013-0038

An air quality permit, with conditions, is hereby granted to Southern Montana Electric Generation and Transmission Cooperative – Highwood Generating Station (SME-HGS), pursuant to Sections 75-2-204 and 211 of the Montana Code Annotated (MCA), as amended, and Administrative Rules of Montana (ARM) 17.8.740, *et seq*., as amended, for the following:

SECTION I: Permitted Facilities

A. Permitted Equipment

SME-HGS operates a gross 270-megawatt (MW) electrical power generating plant. The SME-HGS facility is a coal-fired steam/electric generating station incorporating a circulating fluidized bed boiler (CFB Boiler). Auxiliary power to operate the facility is estimated to be approximately 20 MW resulting in an approximate net power production capacity of 250 MW. Emissions from the CFB-Boiler are controlled by CFB limestone injection technology, a fabric filter baghouse (FFB), a hydrated ash re-injection system (HAR), and a selective non-catalytic reduction unit (SNCR). The total CFB-Boiler emission control strategy is characterized as an integrated emission control system (IECS). A complete list of permitted equipment/emission sources is contained in Section I.A of the permit analysis to this permit.

B. Plant Location

The SME-HGS plant encompasses approximately 720 acres of property and is located approximately 8 miles east of Great Falls, Montana, and approximately 1.5 miles southeast of the Morony Dam on the Missouri River. The legal description of the site is in Section 24 and 25, Township 21 North, Range 5 East, M.P.M., in Cascade County, Montana. The approximate universal transverse mercator (UTM) coordinates are Zone 12, Easting 297.8 kilometers (km), and Northing 5,070.1 km. The site elevation is approximately 3,290 feet above sea level.

C. Supplemental Preliminary Determination

The Department of Environmental Quality (Department) issued a preliminary determination on air quality Permit #3423-00 on March 30, 2006, and accepted comments on the preliminary determination through May 1, 2006. On April 25, 2006, Bison Engineering, Inc., on behalf of SME-HGS, verbally notified the Department of additional emitting units that were not previously analyzed and permitted under Preliminary Determination #3423-00 and are necessary for the construction and operation of the CFB Boiler. SME-HGS submitted an application for the proposed additional emitting units on May 16, 2006.

Specifically, SME-HGS determined that during the CFB Boiler construction phase and periodically thereafter, as necessary, SME-HGS will need to operate portable/temporary propane-fired heaters for the purpose of curing the CFB Boiler refractory brick. In addition, the supplemental preliminary determination corrects various administrative errors contained in the initial preliminary determination. A more detailed discussion of the supplemental preliminary determination permit action is contained in the permit analysis to this permit.

All comments regarding the Department's initial preliminary determination issued for public comment on March 30, 2006, and received by May 1, 2006, have been accepted by the Department as applicable to this supplemental preliminary determination and subsequent comments on the same issues are not necessary. The only changes to the initial preliminary determination under the supplemental preliminary determination are related to the refractory brick curing heaters and administrative errors contained in the initial preliminary determination.

SECTION II: Conditions and Limitations

A. General Plant Requirements

1. SME-HGS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any sources installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 and ARM 17.8.752).

2. SME-HGS shall not cause or authorize emissions to be discharged into the atmosphere from haul roads, access roads, parking lots, or the general plant property without taking reasonable precautions to control emissions of airborne particulate matter (ARM 17.8.308 and ARM 17.8.752).

3. SME-HGS shall treat all unpaved portions of the haul roads, access roads, parking lots, or general plant area with water and/or chemical dust suppressant as necessary to maintain compliance with the reasonable precautions limitation in Section II.A.2 (ARM 17.8.752).

4. SME-HGS shall not cause or authorize the production, handling, transportation, or storage of any material unless reasonable precautions to control emissions of airborne particulate matter are taken. Such emissions of airborne particulate matter from any stationary source shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.308 and ARM 17.8.752).

5. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart Da (ARM 17.8.340 and 40 CFR 60, Subpart Da).

6. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart Db (ARM 17.8.340 and 40 CFR 60, Subpart Db).

7. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart Y (ARM 17.8.340 and 40 CFR 60, Subpart Y).

8. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart OOO (ARM 17.8.340 and 40 CFR 60, Subpart OOO).

9. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 63, Subpart DDDDD, Industrial/Commercial/Institutional/ boiler and Process Heater MACT (ARM 17.8.342 and 40 CFR 63, Subpart DDDDD).

10. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 63, Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE) MACT (ARM 17.8.342 and 40 CFR 63, Subpart ZZZZ).

11. SME-HGS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements of the Acid Rain Program contained in 40 CFR 72-78 (ARM 17.8.1202 and 40 CFR 72-78).

12. SME-HGS shall obtain a written coal analysis that is representative of each load of coal received from each coal supplier. The analysis shall contain, at a minimum, sulfur content, ash content, Btu value (Btu/lb), mercury content, and chlorine content (ARM 17.8.749).

13. SME-HGS shall obtain a written fuel oil analysis for each shipment of fuel oil received from each fuel oil supplier. The analysis shall contain, at a minimum, the sulfur content of the fuel oil and the vapor pressure of the fuel oil (ARM 17.8.749).

B. CFB Boiler Start-Up and Shutdown Operations

1. The requirements contained in Section II.B shall apply during start-up and shutdown operations. CFB start-up and shutdown operations shall be conducted as specified in the *CFB Boiler Start-Up and Shutdown Procedures* included in Attachment 3 of Permit #3423-00 (ARM 17.8.749).

2. CFB Boiler start-up operations, as described in Attachment 3, shall not exceed 48 hours from initial fuel feed to the CFB Boiler (ARM 17.8.749).

3. During start-up and shutdown operations, the CFB Boiler may combust coal with a sulfur content less than or equal to 1% sulfur by weight , fuel oil with a sulfur content less than or equal to 0.05% sulfur by weight, or pipeline quality natural gas (ARM 17.8.752).

4. During start-up and shutdown operations, oxides of nitrogen (NO_x) emissions from the CFB Boiler stack shall not exceed 388 lb/hr (ARM 17.8.749).

5. During start-up and shutdown operations, carbon monoxide (CO) emissions from the CFB Boiler stack shall not exceed 194 lb/hr (ARM 17.8.749).

C. CFB Boiler

1. The CFB Boiler shall combust only coal with a sulfur content less than or equal to 1% sulfur by weight except during periods of start-up or shutdown (ARM 17.8.749 and ARM 17.8.752).

2. SME-HGS shall operate an IECS including CFB limestone injection technology, HAR technology, a SNCR unit, and a FFB for CFB Boiler emissions control except as specified in Attachment 3 during start-up and shutdown operations (ARM 17.8.752).

3. SME-HGS shall not cause or authorize to be discharged into the atmosphere from the CFB Boiler stack any visible emissions that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes except for one 6-minute period per hour of not greater than 27% opacity (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart Da).

4. Filterable particulate matter (filterable PM) emissions from the CFB Boiler stack shall be limited to 0.012 lb/MMBtu and 33.25 lb/hr (ARM 17.8.752).

5. Particulate matter with an aerodynamic diameter les than or equal to 10 microns (PM_{10}) emissions (filterable and condensable) from the CFB Boiler stack shall be limited to 0.026 lb/MMBtu and 72.04 lb/hr (ARM 17.8.752).

6. The CFB Boiler's PM_{10} emission limit shall be used as a surrogate emission limit for radionuclides and trace metals (ARM 17.8.752).

7. Except during periods of start-up and shutdown, NO_x emissions from the CFB Boiler stack shall not exceed the following:

   a. 0.10 lb/MMBtu based on a 1-hour average (ARM 17.8.749 and ARM 17.8.752);

   b. 0.09 lb/MMBtu based on a 24-hour average (ARM 17.8.749 and ARM 17.8.752); and

   c. 0.07 lb/MMBtu based on a rolling 30-day average (ARM 17.8.752).

8. Except during periods of start-up and shutdown, CO emissions from the CFB Boiler stack shall be controlled by proper boiler design and good combustion practices. CO emissions from the CFB Boiler stack shall not exceed 0.10 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).

9. Sulfur dioxide (SO_2) emissions from the CFB Boiler stack shall not exceed the following:

   a. 0.057 lb/MMBtu based on a 3-hour average (ARM 17.8.749 and ARM 17.8.752);

   b. 0.048 lb/MMBtu based on a 24-hour average (ARM 17.8.749 and ARM 17.8.752); and

   c. 0.038 lb/MMBtu based on a rolling 30-day average (ARM 17.8.752).

10. Volatile Organic Compounds (VOC) emissions from the CFB Boiler stack shall be controlled by proper boiler design and good combustion practices. VOC emissions from the Boiler stack shall not exceed 0.003 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).

11. Hydrochloric acid (HCl) emissions from the CFB Boiler stack shall not exceed 0.0021 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).

12. Hydrofluoric acid (HF) emissions from the CFB Boiler stack shall not exceed 0.0017 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).

13. Sulfuric Acid (H_2SO_4) mist emissions from the CFB Boiler stack shall not exceed 0.0054 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).

14. Mercury Emissions

    a. Following commencement of commercial operations (as defined in 40 CFR 60, Subpart HHHH), at the operator's choice, mercury emissions from the CFB Boiler shall not exceed 0.0000015 lb/MMBtu (1.5 pounds per trillion Btu (lb/TBtu)) based on a rolling 12-month average, or an emission rate equal to a 90% or greater reduction of mercury in the as-fired coal, as measured in lb/TBtu and based on a rolling 12-month average. Mercury emissions from the CFB Boiler shall be controlled by the IECS or, at SME-HGS's request and as may be approved by the Department in writing, an equivalent technology (equivalent in removal efficiency) (ARM 17.8.752).

    b. If SME-HGS is unable to comply with the mercury limits, within 18 months after commencement of commercial operations (as defined in 40 CFR 60, Subpart HHHH), SME-HGS shall install and operate an activated carbon injection control system or, at SME-HGS's request and as may be approved by the Department in writing, an equivalent technology (equivalent in removal efficiency) to comply with the applicable mercury emission limits (ARM 17.8.752).

15. Heat input to the CFB-Boiler shall not exceed 23,004,636 MMBtu during any rolling 12-month time period (ARM 17.8.749).

16. The CFB Boiler stack height shall, at a minimum, be maintained at 400 feet above ground level (ARM 17.8.749).

D. Auxiliary Boiler

1. The Auxiliary Boiler shall be limited to 850 hours of operation during any rolling 12-month time period (ARM 17.8.752 and 40 CFR 60, Subpart Db).

2. The Auxiliary Boiler shall combust only fuel-oil with a sulfur content less than or equal to 0.05% sulfur by weight, propane, or pipeline quality natural gas (ARM 17.8.752).

3. SO_2 emissions from the Auxiliary Boiler shall be limited to 12.63 lb/hr (ARM 17.8.749).

4. NO_x emissions from the Auxiliary Boiler shall be controlled by the installation and operation of dry low-NO_x (DLN) burners. NO_x emissions from the Auxiliary Boiler shall be limited to 46.80 lb/hr (ARM 17.8.749 and ARM 17.8.752).

5. CO emissions from the Auxiliary Boiler shall be controlled by proper boiler design and operation and good combustion practices. CO emissions from the Auxiliary Boiler shall be limited to 18.60 lb/hr (ARM 17.8.749 and ARM 17.8.752).

6. VOC emissions from the Auxiliary Boiler shall be controlled by proper boiler design and operation and good combustion practices (ARM 17.8.752).

7. PM_{10} emissions from the Auxiliary Boiler shall be limited to 3.20 lb/hr (ARM 17.8.749).

8. The Auxiliary Boiler stack height shall, at a minimum, be maintained at 220 feet above ground level (ARM 17.8.749).

E. Coal Fuel Processing, Handling, Transfer, and Storage Operations

1. Visible emissions from any Standards of Performance for New Stationary Source (NSPS)-affected equipment shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart Y).

2. All conveyors shall be covered and all outdoor conveyor transfer points shall be covered and vented to a FFB (ARM 17.8.752).

3. All railcar coal deliveries/transfers shall be unloaded within the Rail Unloading Building via belly-dump to a below grade hopper. The Railcar Unloading Building shall be vented to FFB DC1 and maintained under constant negative pressure when coal is being unloaded and conveyed within the building (ARM 17.8.752).

4. PM_{10} emissions from FFB DC1 shall be limited to 0.005 gr/dscf (ARM 17.8.752).

5. All coal deliveries to the Railcar Unloading Building shall be transferred via below ground feeders to a belt conveyor (MC02) (ARM 17.8.752).

6. Transfer Tower 16 shall be enclosed and vented to FFB DC2 (ARM 17.8.752).

7. PM_{10} emissions from FFB DC2 shall be limited to 0.005 gr/dscf (ARM 17.8.752).

8. The emergency coal pile shall be compacted and sprayed with water and/or chemical dust suppressant, as necessary, to maintain compliance with the reasonable precautions requirement and opacity limits (ARM 17.8.752).

9. Coal Silo (CS-1) shall be enclosed and vented to FFB DC2 (ARM 17.8.752).

10. The Coal Crusher House shall be vented to FFB DC3 and shall be maintained under constant negative pressure when processing coal (ARM 17.8.752).

11. The coal crushers (2), surge bin, and rotary feeders (2) shall be enclosed within the Coal Crusher House and vented to FFB D3 (ARM 17.8.752).

12. PM_{10} emissions from FFB D3 shall be limited to 0.005 gr/dscf (ARM 17.8.752).

13. All coal transfers through the tripper system to the day bins located in the CFB Boiler house shall be enclosed and routed to FFB DC4 (ARM 17.8.752).

14. PM_{10} emissions from FFB DC4 shall be limited to 0.005 gr/dscf (ARM 17.8.752).

F. Limestone and Lime Material Processing, Handling, Transfer, and Storage Operations

1. Visible emissions from any NSPS-affected crusher shall not exhibit an opacity of 15% or greater averaged over 6 consecutive minutes (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart OOO).

2. Visible emissions from any other NSPS-affected equipment, such as screens or conveyor transfers, shall not exhibit an opacity of 10% or greater averaged over 6 consecutive minutes (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart OOO).

3. All limestone material shall be delivered to the facility via covered bottom dumping haul-trucks and unloaded within a limestone material unloading drive-through building. The limestone material unloading drive-through building shall be maintained under constant negative pressure and vented through FFB DC5 when limestone material is being unloaded and conveyed within the drive-through building (ARM 17.8.752).

4. All conveyors shall be covered and all outdoor conveyor transfer points shall be covered and vented to FFB DC5 (ARM 17.8.752).

5. All limestone material transfers to the Bucket Elevator and the Limestone Silo shall be vented to FFB DC5 (ARM 17.8.752).

6. PM_{10} emissions from FFB DC5 shall be limited to 0.005 gr/dscf (ARM 17.8.752).

7. Visible emissions from FFB DC5 shall not exhibit an opacity of greater than 7% averaged over 6 consecutive minutes (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart OOO).

G. Fly and Bottom-Ash Material Processing, Handling, Transfer, and Storage Operations

1. Fly-ash shall be pneumatically transferred from the CFB Boiler FFB to the Fly-Ash Silo (AS1) (ARM 17.8.752).

2. Bed-ash shall be pneumatically transferred from the CFB Boiler to the Bed-Ash Silo (AS2) (ARM 17.8.752).

3. PM_{10} emissions resulting from the charging of AS1 and AS2 shall be controlled by fabric filter Bin vents DC6 and DC7, respectively (ARM 17.8.752).

4. Fly-ash and bed-ash shall be gravity-fed into haul trucks through a wet pug-mill for transfer to the on-site ash monofill/landfill (ARM 17.8.752).

5. Air displaced by ash loading into haul trucks shall be vented through AS1 and AS2 and associated bin vents DC6 and DC7, respectively (ARM 17.8.752).

6. PM_{10} emissions from each bin vent DC6 and DC7 shall be limited to 0.01 gr/dscf (ARM 17.8.752).

7. Visible emissions from bin vent DC6 and DC7 shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.752).

H. Coal Thawing Shed Operations

1. The Coal Thawing Shed Heater shall be limited to 240 hours of operation during any rolling 12-month time period (ARM 17.8.749 and ARM 17.8.752).

2. The Coal Thawing Shed Heater shall combust only propane or pipeline quality natural gas (ARM 17.8.752).

3. NO_x, SO_2, CO, VOC, and PM_{10} emissions from the Coal Thawing Shed Heater operations shall be controlled by proper design and operation, good combustion practices, and the combustion of propane and pipeline quality natural gas only (ARM 17.8.752).

I. Emergency Fire Pump Operations

1. The Emergency Fire Pump shall be limited to 500 hours of operation during any rolling 12-month time period (ARM 17.8.749 and ARM 17.8.752).

2. The Emergency Fire Pump shall combust only fuel oil with a sulfur content less than or equal to 0.05% sulfur by weight (ARM 17.8.752).

3. NO_x, SO_2, CO, VOC, and PM_{10} emissions from the Emergency Fire Pump shall be controlled by proper design and operation and good combustion practices (ARM 17.8.752).

J. Emergency Generator Operations

1. The Emergency Generator shall be limited to 500 hours of operation during any rolling 12-month time period (ARM 17.8.749 and ARM 17.8.752).

2. The Emergency Generator shall combust only fuel oil with a sulfur content less than or equal to 0.05% sulfur by weight (ARM 17.8.752).

3. NO_x, SO_2, CO, VOC, and PM_{10} emissions from the Emergency Generator shall be controlled by proper design and operation and good combustion practices (ARM 17.8.752).

4. NO_x emissions from the Emergency Generator shall be limited to 41.20 lb/hr (ARM 17.8.749 and ARM 17.8.752).

5. CO emissions from the Emergency Generator shall be limited to 2.70 lb/hr (ARM 17.8.749 and ARM 17.8.752).

K. Cooling Tower

1. PM_{10} emissions from the Cooling Tower shall be controlled by drift eliminators (ARM 17.8.752).

2. The Cooling Tower drift rate shall be limited to 0.002% of the total circulating water flow (ARM 17.8.752).

L. Fuel Storage Tank

SME-HGS shall not store any liquid fuel with a vapor pressure greater than 3.5 kilopascals (kPa) in the 275,000-gallon capacity fuel storage tank (ARM 17.9.749).

M. CFB Boiler Refractory Brick Curing Heaters

1. SME-HGS shall operate the CFB Boiler refractory brick curing heater(s) only for the purpose of curing CFB Boiler refractory brick. The CFB Boiler refractory brick curing heater(s) shall be limited to a combined maximum of 320 hours of operation during any rolling 12-month time period (ARM 17.8.752).

2. The CFB Boiler refractory brick curing heaters shall combust propane fuel only (ARM 17.8.752).

3. The CFB Boiler refractory brick curing heater(s) shall be limited to a combined maximum heat input capacity of 2771 MMBtu/hr (ARM 17.8.749).

4. SME-HGS shall not operate the CFB Boiler refractory brick curing heater(s) when electricity is being generated through CFB Boiler operations or when the boiler fuel feed (diesel or coal) is operational (ARM 17.8.749).

N. Testing Requirements

1. CFB Boiler Testing Requirements

a. SME-HGS shall initially test the CFB Boiler for opacity within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

After the initial source test, SME-HGS shall use the data from the continuous opacity monitoring system (COMS) to monitor compliance with the applicable opacity limit (ARM 17.8.749).

b. SME-HGS shall initially test the CFB Boiler for filterable PM emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

After the initial source test, additional testing shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

c. SME-HGS shall initially test the CFB Boiler for PM_{10} (filterable and condensable) emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

After the initial source test, additional testing shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

d. SME-HGS shall initially test the CFB Boiler for NO_x emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing. SME-HGS shall conduct the initial performance source testing for NO_x and CO, concurrently (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

After the initial source test, SME-HGS shall use the data from the NO_x continuous emissions monitoring system (CEMS) to monitor compliance with the applicable NO_x emission limits (ARM 17.8.105 and ARM 17.8.749).

e. SME-HGS shall initially test the CFB Boiler for CO emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing. SME-HGS shall conduct the initial performance source testing for CO and NO_x, concurrently (ARM 17.8.105 and ARM 17.8.749).

After the initial source test, additional testing shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and 17.8.749).

f. SME-HGS shall initially test the CFB Boiler for SO_2 emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

After the initial source test, SME-HGS shall use the data from the SO_2 CEMS to monitor compliance with the applicable SO_2 emission limits (ARM 17.8.749).

g. SME-HGS shall initially test the CFB Boiler for HCl emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

After the initial source test, additional testing shall continue on an every 5-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

h. SME-HGS shall initially test the CFB Boiler for HF emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

After the initial source test, additional testing shall continue on an every 5-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and 17.8.749).

i. SME-HGS shall initially test the CFB Boiler for H_2SO_4 emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

After the initial source test, additional testing shall continue on an every 5-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

j. Pursuant to 40 CFR 60.48a through 60.52a and 40 CFR 75, Subpart I, SME-HGS shall monitor compliance with the applicable mercury emission limit(s). Any mercury CEMS used must be operated in compliance with 40 CFR 60, Appendix B (ARM 17.8.105, ARM 17.8.749, 40 CFR 60, Subpart Da, and 40 CFR 75, Subpart I)

2. Coal Fuel, Limestone, and Ash Processing, Handling, Transfer, and Storage Operations Testing Requirements

a. Compliance with the opacity limit for FFB DC1, controlling emissions from rail unloading material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

b. Compliance with the PM_{10} emission limit for FFB DC1 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

c. Compliance with the opacity limit for FFB DC2, controlling emissions from coal silo material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

d. Compliance with the PM_{10} emission limit for FFB DC2 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/ monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 2-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

e. Compliance with the opacity limit for FFB DC3, controlling emissions from coal crusher material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

f. Compliance with the PM_{10} emission limit for FFB DC3 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/ monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 2-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

g. Compliance with the opacity limit for FFB DC4, controlling emissions from tripper deck plant silos material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y and Subpart OOO).

h. Compliance with the PM_{10} emission limit for FFB DC4 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/

monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 2-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y and Subpart OOO).

i. Compliance with the opacity limit for FFB DC5, controlling emissions from limestone material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart OOO).

j. Compliance with the PM_{10} emission limit for FFB DC5 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 2-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart OOO).

k. Compliance with the opacity limit for Bin vent DC6, controlling emissions from ash silo material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105 and ARM 17.8.749).

l. Compliance with the opacity limit for bin vent DC7, controlling emissions from ash silo material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105 and ARM 17.8.749)

3. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

4. The Department may require further testing (ARM 17.8.105).

O. Operational Reporting Requirements

1. SME-HGS shall submit to the Department annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis.

   Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information may be used to calculate operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. SME-HGS shall notify the Department of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location or fuel specifications, or that would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, at least 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

3. All records compiled in accordance with this permit must be maintained by SME-HGS as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

4. SME-HGS shall document, by month, the total heat input to the CFB Boiler. By the 25th day of each month, SME-HGS shall total heat input to the CFB Boiler for the previous month. The monthly information will be used to verify compliance with the rolling 12-month boiler heat input limitation (ARM 17.8.749).

5. SME-HGS shall document, by month, the hours of operation of the Auxiliary Boiler. By the 25th day of each month, SME-HGS shall total the operating hours of the Auxiliary Boiler for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).

6. SME-HGS shall document, by month, the hours of operation of the Emergency Generator. By the 25th day of each month, SME-HGS shall total the operating hours of the Emergency Generator for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).

7. SME-HGS shall document, by month, the hours of operation of the Emergency Fire Water Pump. By the 25th day of each month, SME-HGS shall total the operating hours of the Emergency Fire Water Pump for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).

8. SME-HGS shall document, by month, the hours of operation of the Coal Thawing Shed Heater. By the 25th day of each month, SME-HGS shall total the operating hours of the Coal Thawing Shed Heater for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).

9. SME-HGS shall maintain on site the coal fuel and fuel oil analyses required under Section II.A and submit this information to the Department upon request (ARM 17.8.749).

10. SME-HGS shall maintain a record of CFB Boiler start-up operations. SME-HGS shall document the total start-up operating hours from initial fuel feed to the CFB Boiler for each start-up period. The information shall be submitted to the Department upon request. The information will be used to monitor compliance with the CFB Boiler start-up operating hour limit (ARM 17.8.749).

11. SME-HGS shall monitor and analyze the CFB Boiler mercury control performance data following commencement of commercial operations (as defined in 40 CFR 60, Subpart HHHH). By the 25th day of each month, SME-HGS shall summarize the applicable mercury emissions data (percent reduction and/or emission rate). SME-HGS shall submit this information to the Department quarterly, or according to another reporting schedule as may be approved by the Department. The information will be used to verify the IECS mercury control capabilities (ARM 17.8.749).

12. SME-HGS shall document, by month, the hours of operation of the refractory brick curing heaters. By the 25th day of each month, SME-HGS shall total the operating hours of the refractory brick curing heaters for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).

P. Continuous Emissions Monitoring Systems (CEMS/COMS)

1. SME-HGS shall install, operate, calibrate, and maintain CEMS as follows:

   a. A CEMS for the measurement of SO_2 shall be operated on the CFB Boiler stack (ARM 17.8.105, ARM 17.8.749 and 40 CFR 72-78).

   b. A flow monitoring system to complement the SO_2 monitoring system shall be operated on the CFB Boiler stack (ARM 17.8.105 and 40 CFR 72-78).

   c. A CEMS for the measurement of NO_x shall be operated on the CFB Boiler stack (ARM 17.8.105, ARM 17.8.749 and 40 CFR 72-78).

   d. A COMS for the measurement of opacity shall be operated on the CFB Boiler stack (ARM 17.8.105, ARM 17.8.749 and 40 CFR 72-78).

   e. A CEMS for the measurement of oxygen (O_2) or carbon dioxide (CO_2) content shall be operated on the CFB-Boiler stack (ARM 17.8.105 and ARM 17.8.749).

   f. A CEMS for the measurement of mercury shall be operated on the CFB-Boiler stack (ARM 17.8.105 and ARM 17.8.749).

2. SME-HGS shall determine CO_2 emissions from the CFB Boiler Stack by one of the methods listed in 40 CFR 75.10 (40 CFR 72-78).

3. All continuous monitors required by this permit and by 40 CFR Part 60 shall be operated, excess emissions reported, and performance tests conducted in accordance with the requirements of 40 CFR Part 60, Subpart A; 40 CFR Part 60, Subpart Da; 40 CFR Part 60, Appendix B (Performance Specifications #1, #2, and #3); and 40 CFR Part 72-78, as applicable (ARM 17.8.749 and 40 CFR 72-78).

4. On-going quality assurance for the gas CEMS must conform to 40 CFR Part 60, Appendix F (ARM 17.8.749).

5. SME-HGS shall inspect and audit the COMS annually, using neutral density filters. SME-HGS shall conduct these audits using the applicable procedures and forms in the EPA Technical Assistance Document: Performance Audit Procedures for Opacity Monitors (EPA-450/4-92-010, April 1992). The results of these inspections and audits shall be included in the quarterly excess emission report (ARM 17.8.749).

6. SME-HGS shall maintain a file of all measurements from the CEMS, and performance testing measurements: all CEMS performance evaluations; all CEMS or monitoring device calibration checks and audits; and adjustments and maintenance performed on these systems or devices, recorded in a permanent form suitable for inspection. The records shall be retained on site for at least 5 years following the date of such measurements and reports. SME-HGS shall supply these records to the Department upon request (ARM 17.8.749).

7. SME-HGS shall maintain a file of all measurements from the COMS, and performance testing measurements: all COMS performance evaluations; all COMS or monitoring device calibration checks and audits; and adjustments and maintenance performed on these systems or devices, recorded in a permanent form suitable for inspection. The records shall be retained on site for at least 5 years following the date of such measurements and reports. SME-HGS shall supply these records to the Department upon request (ARM 17.8.749).

Q. Notification

1. Within 30 days after commencement of construction of the SME-HGS facility, SME-HGS shall notify the Department of the date of commencement of construction (ARM 17.8.749)

2. Within 30 days after commencement of construction of the CFB Boiler, SME-HGS shall notify the Department of the date of commencement of construction (40 CFR Part 60.7 and ARM 17.8.749)

3. Within 15 days after actual startup of the CFB Boiler, SME-HGS shall notify the Department of the date of actual startup (40 CFR Part 60.7 and ARM 17.8.749).

4. Within 30 days after commencement of construction of the Auxiliary Boiler, SME-HGS shall notify the Department of the date of commencement of construction (40 CFR Part 60.7 and ARM 17.8.749)

5. Within 15 days after actual startup of the Auxiliary Boiler, SME-HGS shall notify the Department of the date of actual startup (40 CFR Part 60.7 and ARM 17.8.749).

6. Within 30 days after commencement of construction of material handling/processing fabric filter baghouses DC1, DC2, DC3, DC4, and DC5, SME-HGS shall notify the Department of the date of commencement of construction of the affected fabric filter baghouse(s) (40 CFR 60.7 and ARM 17.8.749).

7. Within 15 days after actual startup of material handling/processing fabric filter baghouses DC1, DC2, DC3, DC4, and DC5, SME-HGS shall notify the Department of the date of actual startup of the affected fabric filter baghouse(s) (40 CFR 60.7 and ARM 17.8.749).

8. Within 30 days after commencement of construction of the ash silo fabric filter bin vents DC6 and DC7, respectively, SME-HGS shall notify the Department of the date of commencement of construction of the affected fabric filter bin vent(s) (ARM 17.8.749).

9. Within 15 days after actual startup of the ash silo fabric filter bin vents DC6 and DC7, respectively, SME-HGS shall notify the Department of the date of actual startup of the affected fabric filter bin vent(s) (ARM 17.8.749).

10. Within 30 days after commencement of construction of the CFB Boiler refractory brick curing heater(s), SME-HGS shall notify the Department of the date of commencement of construction of the affected unit(s) and provide the maximum heat input capacity of the affected unit(s) (ARM 17.8.749).

11. Within 15 days after actual startup of the CFB Boiler refractory brick curing heater(s), SME-HGS shall notify the Department of the date of actual startup of the affected fabric filter bin unit(s) (ARM 17.8.749).

SECTION III: General Conditions

A. Inspection – SME-HGS shall allow the Department's representatives access to the facility at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS, COMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver – The permit and the terms, conditions, and matters stated herein shall be deemed accepted if SME-HGS fails to appeal as indicated below.

C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving SME-HGS of the responsibility for complying with any applicable federal or Montana statute or rule, except as specifically provided in ARM 17.8.740, *et seq*. (ARM 17.8.756).

D. Enforcement – Violations of requirements contained herein may constitute grounds for permit revocation, penalties, or other enforcement action as specified in Section 75-2-401, *et seq*., MCA, and ARM 17.8.763.

E. Appeals – Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of

Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.

F. Permit Inspection – As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by the Department at the location of the source.

G. Permit Fee – Pursuant to Section 75-2-220, MCA, as amended by the 2005 Legislature, failure by SME-HGS to pay the annual operation fee may be grounds for revocation of this permit, as allowed by that section and rules adopted thereunder by the Board.

H. Construction Commencement – Construction must begin within 3 years after permit issuance and proceed with due diligence until the project is complete or Permit #3423-00 shall expire. If the permit expires, SME-HGS shall not commence construction until SME-HGS has applied for and received a new air quality permit pursuant to Sections 75-2-204 and 75-2-211, Montana Code Annotated, and ARM 17.8.740 *et seq*., as amended (ARM 17.8.762).

Attachment 2

INSTRUCTIONS FOR COMPLETING EXCESS EMISSION REPORTS (EER)

PART 1 Complete as shown. Report total time during the reporting period in hours. The determination of plant operating time (in hours) includes time during unit start up, shut down, malfunctions, or whenever pollutants of any magnitude are generated, regardless of unit condition or operating load.

Excess emissions include all time periods when emissions, as measured by the CEMS, exceed any applicable emission standard for any applicable time period.

Percent of time in compliance is to be determined as:

(1 – (total hours of excess emissions during reporting period / total hours of CEMS availability during reporting period)) x 100

PART 2 Complete as shown. Report total time the point source operated during the reporting period in hours. The determination of point source operating time includes time during unit start up, shut down, malfunctions, or whenever pollutants (of any magnitude) are generated, regardless of unit condition or operating load.

Percent of time CEMS was available during point source operation is to be determined as:

(1–(CEMS downtime in hours during the reporting period[a] /total hours of point source operation during reporting period)) x 100

a - All time required for calibration and to perform preventative maintenance must be included in the CEMS downtime.

PART 3 Complete a separate sheet for each pollutant control device. Be specific when identifying control equipment operating parameters. For example: number of TR units, energizers for electrostatic precipitators (ESP); pressure drop and effluent temperature for baghouses; and bypass flows and pH levels for scrubbers. For the initial EER, include a diagram or schematic for each piece of control equipment.

PART 4 Use Table I as a guideline to report <u>all</u> excess emissions. Complete a separate sheet for each monitor. Sequential numbering of each excess emission is recommended. For each excess emission, indicate: 1) time and duration, 2) nature and cause, and 3) action taken to correct the condition of excess emissions. Do not use computer reason codes for corrective actions or nature and cause; rather, be specific in the explanation. If no excess emissions occur during the quarter, it must be so stated.

PART 5 Use Table II as a guideline to report all CEM system upsets or malfunctions. Complete a separate sheet for each monitor. List the time, duration, nature and extent of problems, as well as the action taken to return the CEM system to proper operation. Do not use reason codes for nature, extent or corrective actions. Include normal calibrations and maintenance as prescribed by the monitor manufacturer. Do not include zero and span checks.

PART 6 Complete a separate sheet for each pollutant control device. Use Table III as a guideline to report operating status of control equipment during the excess emission. Follow the number sequence as recommended for excess emissions reporting. Report operating parameters consistent with Part 3, Subpart e.

PART 7 Complete a separate sheet for each monitor. Use Table IV as a guideline to summarize excess emissions and monitor availability.

PART 8 Have the person in charge of the overall system and reporting certify the validity of the report by signing in Part 8.

Attachment 2

EXCESS EMISSIONS REPORT

PART 1 – General Information

a. Emission Reporting Period ______________________________

b. Report Date ______________________________

c. Person Completing Report ______________________________

d. Plant Name ______________________________

e. Plant Location ______________________________

f. Person Responsible for Review
and Integrity of Report ______________________________

g. Mailing Address for 1.f. ______________________________

____

h. Phone Number of 1.f. ______________________________

i. Total Time in Reporting Period ______________________________

j. Total Time Plant Operated During Quarter ______________________________

k. Permitted Allowable Emission Rates: Opacity ______________________________

SO_2 __________ NO_x __________ TRS __________

l. Percent of Time Out of Compliance: Opacity ______________________________

SO_2 __________ NO_x __________ TRS __________

m. Amount of Product Produced
During Reporting Period ______________________________

n. Amount of Fuel Used During Reporting Period ______________________________

Attachment 2

PART 2 - Monitor Information: Complete for each monitor.

a. Monitor Type (circle one)

Opacity SO_2 NO_x O_2 CO_2 TRS Flow

b. Manufacturer ______________________________

c. Model No. ______________________________

d. Serial No. ______________________________

e. Automatic Calibration Value: Zero______________ Span ______________

f. Date of Last Monitor Performance Test ______________________________

g. Percent of Time Monitor Available:

1) During reporting period ______________________________

2) During plant operation ______________________________

h. Monitor Repairs or Replaced Components Which Affected or Altered Calibration Values ______________________________

i. Conversion Factor (f-Factor, etc.) ______________________________

j. Location of monitor (e.g. control equipment outlet)______________________________

PART 3 - Parameter Monitor of Process and Control Equipment. (Complete one sheet for each pollutant.)

a. Pollutant (circle one):

Opacity SO_2 NO_x TRS

b. Type of Control Equipment ______________________________

c. Control Equipment Operating Parameters (i.e., delta P, scrubber water flow rate, primary and secondary amps, spark rate)

____

d. Date of Control Equipment Performance Test ______________________________

e. Control Equipment Operating Parameter During Performance Test

____

____

____

____

Attachment 2

PART 4 - Excess Emission (by Pollutant)

Use Table I: Complete table as per instructions. Complete one sheet for each monitor.

PART 5 - Continuous Monitoring System Operation Failures

Use Table II: Complete table as per instructions. Complete one sheet for each monitor.

PART 6 - Control Equipment Operation During Excess Emissions

Use Table III: Complete as per instructions. Complete one sheet for each pollutant control device.

PART 7 - Excess Emissions and CEMS performance Summary Report

Use Table IV: Complete one sheet for each monitor.

PART 8 - Certification for Report Integrity, by person in 1.f.

THIS IS TO CERTIFY THAT, TO THE BEST OF MY KNOWLEDGE, THE INFORMATION PROVIDED IN THE ABOVE REPORT IS COMPLETE AND ACCURATE.

SIGNATURE ______________________________

NAME ______________________________

TITLE ______________________________

DATE ______________________________

Attachment 2

TABLE I

EXCESS EMISSIONS

Date	Time From	Time To	Duration	Magnitude	Explanation/Corrective Action

Attachment 2

TABLE II

CONTINUOUS MONITORING SYSTEM OPERATION FAILURES

Date	Time From	Time To	Duration	Problem/Corrective Action

Attachment 2

TABLE III

CONTROL EQUIPMENT OPERATION DURING EXCESS EMISSIONS

Date	Time From	Time To	Duration	Operating Parameters	Corrective Action

Attachment 2

TABLE IV

Excess Emission and CEMS Performance Summary Report

Pollutant (circle one): SO_2 NO_x TRS H_2S CO Opacity

Monitor ID

Emission data summary [1]	**CEMS performance summary** [1]
1. Duration of excess emissions in reporting period due to: a. Startup/shutdown b. Control equipment problems c. Process problems d. Other known causes e. Unknown causes 2. Total duration of excess emissions 3. $\left[\frac{\text{Total duration of excess emissions}}{\text{Total time CEM operated}} \times 100 = \right]$	1. CEMS[2] downtime in reporting due to: a. Monitor equipment malfunctions b. Non-monitor equipment malfunctions c. Quality assurance calibration d. Other known causes e. Unknown causes 2. Total CEMS downtime 3. $\left[\frac{\text{Total CEMS downtime}}{\text{Total time source emitted}} \times 100 = \right]$

1 For opacity, record all times in minutes. For gases, record all times in hours. Fractions are acceptable (e.g., 4.06 hours)
2 CEMS downtime shall be regarded as any time CEMS is not measuring emissions.

Attachment 3
CFB Boiler Start-Up and Shutdown Procedures
Permit #3423-00

The requirements contained in Section II.B of Montana Air Quality Permit #3423-00 shall apply during CFB Boiler start-up and shutdown operations. CFB Boiler start-up and shutdown operations shall be conducted as specified in this attachment.

I. CFB Boiler Startup

Startup of a circulating fluidized bed (CFB) boiler can take up to 48 hours depending on the initial furnace temperature and condition of the fluidized bed. During the startup process, the unit steps through a series of changes to reach full load firing on coal with the addition of limestone into the CFB furnace. During this process, particulate matter (PM), oxides of nitrogen (NO_x), and sulfur dioxide (SO_2) emissions may vary until air pollution control equipment can be operated at a minimum continuous load.

a. CFB Boiler Bed Material Preparation

The first step in the startup of a CFB involves loading the initial bed material into the furnace. Either sand or used bed ash is loaded into the bed utilizing a pneumatic system. This step can take several hours to complete, during which time there is no fuel combustion taking place. The emissions present during the ash loading cycle are particulate matter. The fabric filter baghouse will collect any of the particulate matter during this step.

b. Startup Hours 1-12

Once the bed material is loaded into the furnace, the fans are started and the CFB Boiler begins to fire on fuel oil. The fuel oil is utilized to warm up the bed material and the CFB Boiler components. The fuel oil usage is increased until the temperature inside the cyclone reaches approximately 1150°F. From a cold start, this process may take 14 hours. During this warm-up period NO_x is controlled through efficient low NO_x fuel oil burners; SO_2 is minimized through the use of low sulfur fuel oil; and PM emissions are controlled by the fabric filter. Carbon monoxide (CO) emissions may be higher than full load operation due to the combustion conditions in the furnace during this period. The firing rate is expected to be approximately 831 million British thermal units per hour (MMBtu/hr) (30% of the maximum CFB Boiler heat input rate of 2,771 MMBtu/hr).

c. Startup Hours 12-18

After approximately 12 hours of firing on fuel oil, coal and limestone are introduced into the furnace and the feed rate is increased over the next 2 hours until the coal becomes the primary fuel source. During this time both fuel oil and coal are combusted together. The fuel oil feed rate is slowly reduced and is eventually shut off. During this transition NO_x is controlled by the use of low NO_x fuel oil burners and the staged combustion of the coal. SO_2 is controlled by the use of low sulfur fuel oil and the addition of limestone to the fluidized bed. The fabric filter continues to control PM.

At approximately 50% of full load the NO_x is further reduced by adding ammonia injection via the Selective Non-catalytic Reduction (SNCR) system. In addition, approximately 4 hours after limestone is injected into the fluidized bed, the hydrated ash reinjection system is activated to further reduce SO_2 emissions. At this point all emissions control equipment is fully activated. The total time to reach a point where all air pollution control technologies are operating is approximately 18 hours from a cold start. Start-up operations are limited, by permit, to a maximum of 48 hours.

Attachment 3
CFB Boiler Start-Up and Shutdown Procedures
Permit #3423-00

II. CFB Boiler Shutdown

Several steps are required for a controlled shutdown of the boiler and the associated ancillary equipment. The first step of the process is to shut down the coal feed into the furnace. In order to accomplish this, the coal feed and firing rate is gradually reduced. As the temperature is reduced below the minimum requirements for the hydrated ash re-injection and SNCR systems, these systems are turned off. The furnace is brought down to the minimum coal firing rate. At this point the coal feed is completely shut off and the furnace is purged with air. The air will be used to gradually lower the boiler temperature for inspection or maintenance. Once the boiler is cooled off, the ID Fan will be turned off. If no access into the furnace is required, the bed ash will be left in the furnace area of the CFB Boiler. If access is required, the bed ash will be discharged and pneumatically conveyed to the ash silo, where it will be stored until the next startup. In the event that the boiler shutdown is only for a short period, and re-operation of the unit is anticipated, the fans will be turned off, and the ID Fan control damper will be closed in order to bottle up the furnace and maintain the maximum amount of heat.

Permit Analysis
Southern Montana Electric Generation and Transmission Cooperative – Highwood Generating Station
Permit #3423-00

I. Introduction/Process Description

A. Permitted Equipment

Southern Montana Electric Generation and Transmission Cooperative – Highwood Generating Station (SME-HGS) operates a net 250-megawatt (MW) electrical power generating plant located approximately 8 miles east of Great Falls, Montana, and approximately 1.5 miles southeast of the Morony Dam on the Missouri River. The legal description of the site is in Section 24 and 25, Township 21 North, Range 5 East, M.P.M., in Cascade County, Montana. The approximate universal transverse mercator (UTM) coordinates are Zone 12, Easting 297.8 kilometers (km), and Northing 5,070.1 km. The site elevation is approximately 3,290 feet above seal level.

The SME-HGS facility is a coal-fired steam/electric generating station incorporating a circulating fluidized bed boiler (CFB Boiler) with an average annual heat input value of 2,626 million British thermal units per hour (MMBtu/hr) and a maximum short-term heat input capacity of 2,771 MMBtu/hr to produce approximately 1.8 million pounds of steam per hour. The steam is routed to a steam turbine, which drives an electric generator capable of producing an estimated 270 gross MW of electrical power. Auxiliary power to operate the facility is estimated to be approximately 20 MW resulting in the approximate net power production capacity of 250 MW. The following equipment/emission sources are permitted for this facility:

- 2771 MMbtu/hr heat input capacity coal fired CFB Boiler (2626 MMBtu/hr average)
- 225 MMBtu/hr heat input capacity diesel fuel-oil, propane, or natural gas fired Auxiliary Boiler
- 2000 kilowatt (kW) emergency diesel fuel-oil fired generator set
- 230 Kw emergency diesel fuel-oil fired Emergency fire pump
- 40 MMBtu/hr heat input capacity propane/natural gas fired Coal Thawing Shed Heater
- Cooling Tower
- Fabric Filter Baghouse (FFB) DC1 controlling rail unloading material transfers
- FFB DC2 controlling coal silo material transfers
- FFB DC3 controlling coal crusher operation and material transfers
- FFB DC4 controlling tripper deck plant silos material transfers
- FFB DC5 controlling limestone material transfers
- Fabric Filter bin vent DC6 controlling fly ash silo (AS-1) material transfers
- Bin vent DC7 controlling bottom ash silo (AS-2) material transfers
- Emergency Coal Storage Pile
- Ash Storage/Disposal Monofill
- 275,000 gallon capacity diesel fuel-oil storage tank
- Haul Roads/vehicle traffic
- 2771 MMBtu/hr heat input capacity portable/temporary propane fired CFB Boiler refractory brick curing heater(s)

B. Source Description

1. CFB Boiler

The CFB Boiler will combust low-sulfur coal except during periods of start-up and shutdown where pipeline quality natural gas, propane, or low-sulfur diesel fuel-oil may be combusted. Regulated pollutants emitted from the CFB-Boiler will be controlled by CFB limestone injection technology, a fabric filter baghouse (FFB), a hydrated ash re-injection system (HAR), and a selective non-catalytic reduction unit (SNCR). The total CFB-Boiler emission control strategy is characterized as an integrated emission control system (IECS).

The CFB Boiler technology uses a bed of crushed coal and limestone and recycled heavy ash particles suspended (fluidized) in an upwardly flowing air stream. Air enters near the bottom of the furnace and is staged through air distribution nozzles to minimize the formation of NO_x. The coal and limestone are metered and fed into the furnace bed. Combustion takes place in the fluidized bed, which is limited in temperature to reduce the formation of NO_x. The fine particles of limestone react with the sulfur in the coal and reduce the formation of SO_2. The heavier combustion byproduct particles are carried in the flue gas through the furnace, collected in a cyclone separator, and are then circulated back into the furnace.

The SNCR system is used to control NO_x emissions. Ammonia (NH_3) is injected into the cyclone separator and mixed with the flue gas. The NH_3 reacts with the flue gas to convert NO_x into nitrogen gas (N_2), and water vapor (H_2O). The HAR system is used to control SO_2 emissions. The HAR is a dry flue gas desulfurization process; the system mixes water with fly ash and available lime (produced during heating of the limestone in the CFB Boiler) to react with the SO_2 in the flue gas to form particulate, which is collected downstream in FFB. The FFB is used for particulate emissions control. The fabric filter consists of multiple fabric bags that capture lighter particles in the exhaust gases downstream of the cyclone separator. These lighter particles include fly ash and lighter solids created in the chemical reaction processes. Carbon monoxide (CO) and Volatile Organic Compounds (VOC) emissions will be controlled by best management practices (BMP) and staged combustion of air ensuring proper operation of the CFB Boiler. Limestone injection in the CFB Boiler and the HAR system, collectively, will also remove acid gases including sulfuric acid (H_2SO_4), hydrochloric acid (HCl) and hydrofluoric acid (HF). In addition, the FFB will reduce emissions of metals including antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, mercury, and manganese. A co-benefit of mercury emission reduction will result from the overall IECS design. Absorption of mercury will be realized in the CFB Boiler due to the source of unburned carbon, use of limestone injection, SNCR, and the HAR system. The mercury in particulate form will then be collected in the FFB. In addition, mercury specific emission controls may be required (see mercury BACT analysis and determination, Section III, Permit Analysis). After passing through the FFB, the flue gas will exit to atmosphere through the 400-feet tall CFB Boiler stack. The height of the stack was selected to minimize the visual impact of the plant while maintaining adequate dispersion.

2. Auxiliary Boiler, Emergency Generator, Emergency Fire Pump, and Coal Thawing Shed

The auxiliary boiler will combust #2 diesel fuel, natural gas, or propane and will only be in operation during periods of CFB Boiler startup, shutdown, commissioning and during extended downtimes of the CFB Boiler during winter months to aid in the prevention of freezing of the CFB Boiler components. The Emergency Generator and Emergency Fire

Pump will combust only low-sulfur diesel fuel-oil and operate only during emergencies and during required maintenance. The Coal Thawing Shed Heater will only operate on propane or natural gas during times when the coal is frozen in the coal train cars.

3. Cooling Tower

A wet cooling tower will be used to dissipate the heat from the condenser by using the latent heat of water vaporization to exchange heat between the process and the air passing through the cooling tower. The cooling tower will be an induced, counter flow draft design equipped with drift eliminators. The average make-up water rate for the proposed cooling tower will be approximately 2,250 gallons per minute (gpm). Water will be delivered to the facility via pipeline from the Missouri River.

4. Coal Fuel Processing, Handling, Transfer, and Storage Operations

Facility operations will utilize several proposed conveyors, transfer points, and storage facilities to handle the coal fuel material required for the operation of the CFB Boiler. The coal storage and handling system begins with coal delivered by railcars to the SME-HGS facility. Coal deliveries are estimated to be two trains per week or approximately 22,000 tons of coal.

The coal delivery railcars will pass through the Coal Thawing Shed, which will thaw frozen wintertime coal shipments before the railcars enter the Rail Unloading Building. Inside the Rail Unloading Building the coal railcars will be unloaded via a belly dump into a below-grade hopper. From the hopper, the coal will be transferred onto a covered belt conveyor (MC02). The Rail Unloading Building will be vented to an induced draft FFB DC1, which will maintain a constant negative pressure within the building. FFB DC1will provide emission control for coal transfers from the below-grade feeders to conveyor MC02. MC02 will deliver the coal to the enclosed Transfer Tower 16. The Transfer Tower will be vented to the induced draft FFB DC2 located near the coal silo. The Transfer Tower will direct the coal to either the coal silo or to the outdoor long-term coal storage pile (emergency coal pile). The emergency coal pile will store enough coal to supply the CFB Boiler for approximately one month and be used during interruptions in coal deliveries. The emergency coal pile will be compacted and sprayed with water or surfactant to minimize coal dust emissions. Coal transferred to the emergency coal storage pile will be diverted to the Coal Stackout Conveyor (CC01) and will then enter the Lowering Well where emissions will be controlled by the Lowering Well design. Coal will be reclaimed from the coal storage pile by below-grade vibrating reclaim hoppers and a belt feeder. The reclaimed coal will be moved onto the Coal Reclaim Conveyor (CC03) and returned to Transfer Tower 16. Coal not directed to the emergency coal pile or reclaimed from the emergency coal pile will be transferred to the Coal Transfer Conveyor (CC02) inside Transfer Tower 16. CC02 feeds the Coal Silo (CS-1), which is sized to hold coal for several days of CFB Boiler operations. The coal transfers associated with CC04 are controlled by FFB DC2 located at the coal silo. FFB DC2 will also control coal dust emissions from the transfer of coal from the feeder located at the bottom of CS-1 to Coal Feeder Conveyor (CC04). CC04 transfers coal to the Coal Crusher House which encloses a coal surge bin, two rotary feeders, and two coal crushers and is controlled by FFB DC3, which also controls emissions from the Coal Transfer Conveyor CC05. Crushed coal on CC06 is transferred to the Tripper System (comprised of the Tripper Conveyor and Traveling Tripper) and is controlled by FFB DC4.

5. Limestone Processing, Handling, Transfer, and Storage Operations

Covered, over-the-highway, bottom-dumping trucks will deliver limestone material to the SME-HGS facility and will be unloaded in a drive-through building, which is controlled by FFB DC5. The Limestone Transfer Conveyor (LC01) will move the delivered limestone to the Limestone Bucket Elevator (LC02), and discharge into the Limestone Silo (LS1). LS1 loading and unloading limestone dust emissions from this silo will also be controlled by FFB DC5. Limestone unloaded from the silo will be transferred to a feed chute by the Limestone Weight Feeder (LC03). The feed chute dumps directly into the Limestone Mills, which feed directly into the furnace of the boiler.

6. Fly and Bed Ash Handling, Transfer, and Storage/Disposal Operations

Combustion of coal in the CFB Boiler will produce two types of dry ash: bed ash (20-30%) and fly ash (70-80%). Both fly ash and bed ash will be dry and will be collected in two separate ash silos. Fly ash collected by the baghouse will be pneumatically transferred to the fly ash silo (AS1). Air displaced by fly ash silo charging will be controlled by Bin-Vent DC6, while bed ash from the CFB Boiler will be transferred pneumatically to the bed ash silo (AS2) where emissions will be controlled by a bin vent DC7. Bed ash and fly ash will be gravity-fed into trucks through a pug mill where water and ash are mixed to reduce dust generation. Air displaced by ash loading into trucks will be vented through AS1 and AS2 and their associated bin vents DC6 and DC7, respectively. The ash will be transferred from AS1 and AS2 to trucks and disposed of in the on-site ash monofill. In addition to disposal on-site, SME-HGS is researching beneficial uses for the ash.

7. Fuel-Oil Storage Tank

The diesel fuel will be used for CFB Boiler startup, shut-down, and commissioning operations, auxiliary boiler operations, emergency generator operations, and emergency fire pump operations, and will be stored in an above-ground fuel tank. The tank will hold up to 275,000 gallons of #2 diesel fuel. The tank will be limited to the storage of fuels with a vapor pressure of 3.5 kilopascals (kPa) or less to avoid 40 CFR 60, Subpart Kb, applicability.

8. Haul Roads

Trucks will be used for the delivery of limestone and the transport of ash to the monofill. The facility will also have bulldozers and front-end loaders, which will be utilized to maintain the emergency coal storage pile. SME-HGS will use BMP, including water sprays, to reduce fugitive emissions from unpaved work areas and roadways.

9. CFB Boiler Refractory Brick Curing Heaters

Because information on the final CFB Boiler design is dependent on the choice of boiler manufacturer and this information is not available at the time of application for this supplemental preliminary determination, SME-HGS formulated a conservative refractory brick curing scenario (i.e., scenario with conservatively high emission rates). This scenario includes a total heat input to cure the CFB Boiler refractory brick that would not exceed the maximum hourly heat input to the CFB Boiler of 2771 MMBtu/hr. The CFB Boiler refractory brick curing heater(s) shall be limited to a combined maximum of 320 hours of operation per year and shall combust only propane fuel.

C. Permit History

The Department issued a preliminary determination on air quality Permit #3423-00 on March 30, 2006, and accepted comments on the preliminary determination through May 1, 2006. On April 25, 2006, Bison Engineering, Inc., on behalf of SME-HGS, verbally notified the Department of additional air pollutant emitting units that were not previously analyzed and permitted under Preliminary Determination #3423-00 and are necessary for the construction and operation of the CFB Boiler. SME-HGS submitted an application for the proposed additional emitting units on May 16, 2006. Because these units were not included in the initial preliminary determination, the Department issued a supplemental preliminary determination for public comment.

D. Supplemental Preliminary Determination

SME-HGS determined that during the CFB Boiler construction phase and periodically thereafter, as necessary, SME-HGS will need to operate portable/temporary propane-fired heater(s) for the purpose of curing the CFB Boiler refractory brick (refractory heaters). At the time of application for the supplemental preliminary determination, SME-HGS had not determined the specific boiler manufacturer to supply the CFB Boiler for the proposed project; therefore, specific information regarding the refractory heaters was not available prior to application for the supplemental preliminary determination. In light of this, The Department required that SME-HGS provide a conservative analysis of potential worst-case impacts resulting from operation of the proposed refractory heater(s).

SME-HGS formulated a conservative refractory heater operating scenario (i.e., a scenario with conservatively high emission rates). The scenario proposes a total refractory heater heat input limit that would not exceed the maximum hourly heat input to the CFB Boiler of 2771 MMBtu/hr, as reported in the initial application for air quality Permit #3423-00. The refractory heaters would potentially combust approximately 30,280 gallons of propane per day to achieve this conservatively estimated heat input scenario. The analysis of potential impacts and the Department's Best Available Control Technology (BACT) determination for the proposed refractory heaters is based on the above-cited maximum heat input scenario firing propane and an annual operating limit of 320 hours per year to accommodate initial and periodic refractory heater(s) operations. In addition, the CFB Boiler refractory brick heater(s) emissions exhaust will exit the CFB Boiler through a temporary stack 11 feet in diameter and 210 feet tall. The stack will be located above the CFB Boiler cyclone. The required BACT analysis for the refractory heater(s) project is contained in Section III.F of the permit analysis to this permit. SME-HGS modeled potential impacts from the portable/temporary CFB Boiler refractory brick curing heater(s) and the modeling conducted for the project demonstrates compliance with all applicable standards.

In addition, the following administrative errors contained in the Department's initial preliminary determination have been corrected under this supplemental preliminary determination:

- Correction of applicable Auxiliary Boiler PM_{10} emission limit in Section II.D.7 of the permit. The correct emission limit is 3.20 lb/hr not 5.43 lb/hr as required in the Department's initial preliminary determination;
- Table contained in Section III.A.5.C of the permit analysis, CFB Boiler VOC BACT Analysis, corrected to indicate "VOC" not "CO" emission rates, as reported in the Department's initial preliminary determination;

- The CFB Boiler mercury emission estimate contained in Section IV, Emission Inventory, of the permit analysis, has been modified from an estimate of 0.02 tons per year reported in the Department's initial preliminary determination to 0.017 tons per year to reflect potential mercury emissions resulting from the permitted mercury BACT emission limit of 1.5 lb/TBtu.
- Correction of the years of surface and upper air meteorological data used to demonstrate compliance with the Class II modeling contained in the second paragraph in Section VI of the permit analysis, Ambient Impact Analysis. The correct years of meteorological data are 1987-1991 and not 1984, 1986-1991, as reported in the Department's initial preliminary determination.
- Correction of modeled concentration of CO reported in Table 1, Section VI, Ambient Air Impact Analysis, from 662 ug/m^3 reported in the Department's initial preliminary determination to 66.2 ug/m^3 and the reported net increase of VOC from 36.5 reported in the Department's initial preliminary determination to 35.6 tons per year.
- Correction of the NO_x control efficiencies reported in the Department's initial preliminary determination for SCR, SNCR, and baseline uncontrolled CFB Boiler emissions in the table in Section III.A.3.C of the permit analysis. The correct control efficiencies are 90% for SCR, 50% for SNCR, and 0% for uncontrolled baseline emissions.
- Addition of footnote to Emission Inventory table contained in Section IV of the permit analysis to clarify estimated PM and PM_{10} emissions from the CFB Boiler.
- Correction of SNCR urea chemical reaction contained in Section III.A.3.A.vi, BACT Determination, of the permit analysis.

All comments regarding the Department's initial preliminary determination issued for public comment on March 30, 2006, and received by May 1, 2006, have been accepted by the Department as applicable to this supplemental preliminary determination and subsequent comments on the same issues are not necessary. The only changes to the initial preliminary determination under the supplemental preliminary determination are related to the refractory brick curing heaters and administrative errors contained in the initial preliminary determination, as detailed above. The supplemental Preliminary Determination #3423-00 replaces the initial Preliminary Determination #3423-00 issued for public comment on March 30, 2006.

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the Administrative Rules of Montana (ARM) and are available, upon request, from the Department. Upon request, the Department will provide references for location of complete copies of all applicable rules and regulations or copies where appropriate.

A. ARM 17.8, Subchapter 1 – General Provisions, including but not limited to:

1. ARM 17.8.101 Definitions. This rule includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment (including instruments and sensing devices) and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by the Department.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., Montana Code Annotated (MCA).

   SME-HGS shall comply with the requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

4. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction of the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner as to create a public nuisance.

B. ARM 17.8, Subchapter 2 – Ambient Air Quality, including, but not limited to the following:

1. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
2. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
3. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
4. ARM 17.8.213 Ambient Air Quality Standard for Ozone
5. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
6. ARM 17.8.221 Ambient Air Quality Standard for Visibility
7. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}

SME-HGS must maintain compliance with the applicable ambient air quality standards.

C. ARM 17.8, Subchapter 3 – Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, SME-HGS shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.

3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.

4. ARM 17.8.310 Particulate Matter, Industrial Process. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this rule.

5. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. This rule requires that no person shall burn liquid, solid, or gaseous fuel in excess of the amount set forth in this rule.

6. ARM 17.8.324 Hydrocarbon Emissions--Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule.

7. ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources. This rule incorporates, by reference, 40 CFR 60, Standards of Performance for New Stationary Sources (NSPS). SME-HGS is an NSPS affected facility under 40 CFR 60 and is subject to the requirements of the following subparts:

   a. 40 CFR 60, Subpart A. The general provisions provided in 40 CFR 60, Subpart A, apply to all equipment or facilities subject to any Subpart listed below

   b. 40 CFR 60, Subpart Da. As applicable to CFB Boiler and associated affected equipment.

   c. 40 CFR 60, Subpart Db. As applicable to Auxiliary Boiler and associated affected equipment.

   d. 40 CFR 60, Subpart Y. As applicable to coal processing, handling, and storage equipment and activities.

   e. 40 CFR 60, Subpart OOO. As applicable to limestone processing, handling, and storage equipment and activities.

   f. 40 CFR 60, Subpart HHHH. Model rules for a Mercury Budget Trading Program.

8. ARM 17.8.341 Emission Standards for Hazardous Air pollutants. This source shall comply with the standards and provisions of 40 CFR 61, as appropriate.

9. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR 63, shall comply with the requirements of 40 CFR 63, as listed below:

   a. 40 CFR 63, Subpart A. The general provisions provided in 40 CFR 63, Subpart A, apply to all equipment or facilities subject to any Subpart listed below:

   b. 40 CFR 63, Subpart B. As applicable facility wide.

   c. 40 CFR 63, Subpart ZZZZ. As applicable to the Emergency Generator.

   d. 40 CFR 63, Subpart DDDDD. As applicable to the Auxiliary Boiler.

D. ARM 17.8, Subchapter 4 – Stack Height and Dispersion Techniques, including, but not limited to:

1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.402 Requirements. SME-HGS must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP). The proposed height of the stacks for the SME-HGS CFB Boiler and Auxiliary Boiler are below the allowable GEP stack height and SME-HGS has demonstrated compliance with all applicable ambient air quality standards as part of the complete permit application for this permit.

E. ARM 17.8, Subchapter 5 – Air Quality Permit Application, Operation, and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. SME-HGS submitted the appropriate permit application fee for the current permit action.

2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit (excluding an open burning permit) issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

   An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The Department may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.

F. ARM 17.8, Subchapter 7 – Permit, Construction, and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit modification to construct, modify, or use any air contaminant sources that have the Potential to Emit (PTE) greater than 25 tons per year of any pollutant. SME-HGS has a PTE greater than 25 tons per year of PM, PM_{10}, NO_x, CO, SO_2, and VOC; therefore, an air quality permit is required.

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

4. ARM 17.8.745 Montana Air Quality Permits--Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, alteration, or use of a source. SME-HGS submitted the required permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. SME-HGS submitted an affidavit of publication of public notice for the December 7, 2005, issue of the *Great Falls Tribune*, a newspaper of general circulation in the Town of Great Falls in Cascade County, as proof of compliance with the public notice requirements.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this permit analysis.

8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving SME-HGS of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*.

10. ARM 17.8.760 Additional Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those applications that require an environmental impact statement.

11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or altered source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of Intent to Transfer, including the names of the transferor and the transferee, is sent to the Department.

G. ARM 17.8, Subchapter 8 – Prevention of Significant Deterioration of Air Quality, including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification, with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow.

This facility is a listed source because it is a fossil-fuel fired steam-electric generating plant having more than 250 MMBtu/hr heat input capacity. Furthermore, the facility's emissions of PM, PM_{10}, NO_X, SO_2, and CO are greater than 100 tons per year; therefore, the facility is a major source under the New Source Review Prevention of Significant Deterioration (PSD) program.

H. ARM 17.8, Subchapter 12 – Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any source having:

   a. PTE > 100 tons/year of any pollutant;

   b. PTE > 10 tons/year of any one Hazardous Air Pollutant (HAP), PTE > 25 tons/year of a combination of all HAPs, or lesser quantity as the Department may establish by rule; or

   c. PTE > 70 tons/year of particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program. (1) Title V of the FCAA amendments of 1990 requires that all sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing Air Quality Permit #3423-00 for SME-HGS, the following conclusions were made:

   a. The facility's PTE is greater than 100 tons/year for PM, PM_{10}, NO_X, SO_2, and CO.

b. The facility's PTE is greater than 10 tons/year for any one HAP and greater than 25 tons/year for all HAPs.

c. This source is not located in a serious PM_{10} nonattainment area.

d. This facility is subject to NSPS requirements under 40 CFR 60, Subpart(s) A, Da, Db, Y, and OOO.

e. This facility is subject to NESHAP standards under 40 CFR 60, subpart DDDDD and ZZZZ, as applicable.

f. This source is a Title IV affected source.

g. This source is not a solid waste combustion unit.

h. This source is not an EPA designated Title V source.

Based on the above information, the SME-HGS facility is a major source of air pollutants as defined under the Title V operating permit program; therefore, a Title V Operating Permit is required. SME-HGS submitted an application for a major source Title V operating permit concurrent with the submittal of the application for Montana Air Quality Permit #3423-00.

III. BACT Determination

A BACT determination is required for each new or modified source of emissions. SME-HGS shall install on the new or modified source of emissions the maximum air pollution control capability that is technically practicable and economically feasible, except that the BACT shall be utilized.

Under the current permit action, SME-HGS proposed a coal-fired power plant incorporating a CFB Boiler for the production of steam to be routed to a steam turbine, which in turn drives an electric generator capable of producing electrical power. The United States Environmental Protection Agency's (EPA) Draft New Source Review Workshop Manual (October 1990) (NSR Manual) states that, "historically, EPA has not considered the BACT requirement a means to re-define the design of the source when considering available control technologies." However, the NSR Manual goes on to indicate "…this is an aspect of the New Source Review – Prevention of Significant Deterioration permitting process in which states have the discretion to engage in a broader analysis if they so desire." Based on the analysis provided below, the Department does not believe that redefining the source is appropriate in this case.

In support of the Department's position on this issue, a recent EPA policy/guidance statement titled *Best Available Control Technology Requirements for Coal-Fired Power Plants,* authored by Stephen D. Page, Director, EPA Office of Air Quality, Planning, and Standards (December 13, 2005), provides that inclusion of technologies such as integrated gasification combined cycle (IGCC) in the BACT analysis for a coal-fired power plant, such as that proposed in this case, constitutes re-definition of the source and is not appropriate under the BACT analysis and determination process.

Despite the above-cited reasons for not requiring consideration of other energy production processes, during the research and development phase leading to the proposed SME-HGS project, SME-HGS evaluated various alternative energy technologies including the following: Wind; Solar - Photovoltaic; Solar - Thermal; Hydroelectric; Geothermal; Biomass; Biogas; Municipal Solid Waste; Natural Gas Combined Cycle; Microturbines; Pulverized Coal (PC) Boilers; CFB Boilers; and

IGCC. This analysis is compiled in a document created for the U.S. Department of Agriculture, Rural Utility Service (RUS) titled, A*lternative Evaluation Study* (AES). A copy of this document is available for review on the RUS website at www.usda.gov/rus/water/ees/eis.htm and in Appendix D of the SME-HGS application for this air quality permit. This document constitutes a detailed study of alternative energy technologies that were analyzed for future power requirements. The purpose of the AES, as stated in the AES document is "…to determine *an appropriate source of wholesale electric energy and related services post 2008…Provide an analysis of alternatives that SME-HGS has considered to meet its wholesale energy and related supply obligations currently met through the use of power purchase agreements…The alternatives studied by SME-HGS were evaluated in terms of cost effectiveness, technical feasibility, and environmental soundness."*

Additional Evaluation of IGCC and PC Technology

As previously stated, the Department determined that re-defining the proposed CFB coal-fired power project is not appropriate in this case. However, because IGCC and PC technologies represent available and technically feasible electrical power production technologies using coal as fuel, the following information has been summarized to provide additional basis for rejecting these technologies as BACT for the proposed SME-HGS project based on technical, environmental, and economic factors.

IGCC Power Generation

Based on the analysis included in the SME-HGS application materials and independent Department research, the Department determined that IGCC represents an available and potentially technically feasible strategy for the production of electricity using coal. However, the Department determined that IGCC is technically, economically, and environmentally infeasible for the purpose of meeting the SME-HGS wholesale energy and related supply obligations to its energy cooperative customers.

As provided in the NSR Manual (Section B-19), an analysis of technical feasibility should include an evaluation of the capabilities of the technology for project specific application. At the time of draft permit issuance, IGCC has not been adequately demonstrated to provide acceptable reliability, with current approaches to improving reliability resulting in less efficient facilities thereby negatively impacting the cost-competitiveness of IGCC for a base-load power generation project. Currently, IGCC incurs an approximate 20% increase in project cost-effective values when compared to CFB power production projects. Therefore, the Department determined that the application of IGCC for the proposed SME-HGS project presents currently un-resolvable reliability concerns leading to unacceptable project cost increases.

Further, based on Department analysis of existing and currently operational similar sized IGCC plant operations, the Department determined that criteria pollutant emissions from IGCC plants, when compared to CFB technology, result in relatively little or no additional environmental protection. The Department understands that the carbon sequestration (greenhouse gas reduction) capabilities of the IGCC technology potentially represents a significant environmental benefit associated with the application of this technology when compared to historically prevalent coal-fired power plant projects (CFB and PC). However, greenhouse gasses, such as carbon dioxide (CO_2), are not currently regulated under the Montana or federal Clean Air Act. Therefore, because IGCC results in relatively little increased regulated environmental protection, the environmental benefits associated with IGCC greenhouse gas sequestration capabilities do not justify application of this technology for the proposed project.

As summarized above, the Department determined that, at this time, IGCC constitutes a technically, economically, and environmentally infeasible alternative electric power production alternative for the proposed SME-HGS project; therefore, IGCC is eliminated from further consideration under the BACT analysis and determination process.

PC-Boiler Power Generation

Based on the analysis included in the SME-HGS application materials and direct recent and historical Department experience in permitting PC-fired electrical power production projects, the Department determined that PC-fired electrical power production represents an available, technically feasible, and cost-effective strategy for the production of electricity using coal. However, the Department determined that PC-fired electrical power generation does not constitute BACT in this case considering the environmental benefits associated with the proposed CFB coal-fired power project when compared to a PC coal-fired power project.

Operation of a PC-fired boiler in place of the proposed CFB Boiler for the SME-HGS project would result in significantly increased emissions of SO_2, CO, PM_{10}, and total HAPs and relatively similar emissions of NO_x and mercury (specific HAP). Therefore, because SME-HGS proposed a CFB electrical power generation project and the CFB technology would result in less emissions of regulated air pollutants when compared to the PC-fired technology, the Department determined that PC-fired electrical power generation does not constitute BACT in this case.

Project BACT Applicability

The Department determined that the proposed CFB coal-fired power plant represents the most appropriate technology to supply energy to SME-HGS customers taking into consideration technical, environmental, and economic factors. Coal-fired electrical power generation, specifically CFB coal combustion is carried forward into the following BACT analysis and determination process. The following BACT analysis addresses available methods of controlling air pollutant emissions from the following affected equipment:

- CFB Boiler: SO_2, filterable PM, PM_{10} (filterable and condensable), NO_x, CO, VOC, H_2SO_4, acid gasses (HCl and HF), trace metals, radionuclides, and mercury.
- Coal, Limestone, and Ash (Bottom and Fly Ash) Material Processing, Handling, Transfer, and Storage Operations: PM/PM_{10}
- Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater: PM_{10}, NO_x, CO, SO_2, and VOC.
- Cooling Tower: PM/PM_{10}
- Haul Roads/Truck Traffic: PM/PM_{10}
- CFB Boiler Refractory Brick Curing Heaters: PM_{10}, NO_x, CO, SO_2, and VOC.

The Department reviewed the following control options, as well as previous BACT determinations for similar permitted sources in order to make the following pollutant specific BACT determinations.

A. CFB Boiler BACT Analysis and Determination

1. SO_2 Emissions

Sulfur oxide (SO_x) emissions from fossil fuel combustion consist primarily of SO_2. Additional compounds of SO_x also form at a much lower quantity and consist of sulfur trioxide (SO_3) and gaseous sulfates. These compounds form as the sulfur in the fossil fuel is oxidized during the combustion process. SME-HGS is proposing to use Powder

River Basin (PRB) sub-bituminous coal as the CFB Boiler fuel source and, as such, has analyzed the use of low-sulfur coal for the proposed project.
Low sulfur coal is typically considered coal with sulfur content at or below 1.0% by weight. Sulfur content and heating content of coal can vary between coal mine and coal seam, which can impact SO_2 emissions from the source. High sulfur coal is typically between 1% and 5% sulfur by weight. Coal analyzed for the proposed project will typically have sulfur content less than 0.8% by weight and heating values greater than 8,600 Btu/lb.

A. Identification of Available SO_2 Control Strategies/Technologies

Several techniques can be used to reduce SO_2 emissions from CFB Boiler fossil fuel combustion. SO_2 control options can be divided into pre-combustion strategies (e.g., combusting low sulfur fuels, fuel blending, coal cleaning, etc.), combustion techniques, and post-combustion controls typically characterized as flue gas de-sulfurization (FGD) units (e.g., wet scrubbers, dry scrubbers, etc.). The following available SO_2 control options/technologies/strategies were evaluated for the proposed project:

i. CFB Boiler with High-Sulfur Coal
ii. CFB Boiler with Low-Sulfur Coal (Fuel Blending or Switching)
iii. CFB Boiler with Limestone Injection
iv. CFB Boiler with Coal Cleaning
v. CFB Boiler with FGD
  a. Wet Lime Scrubber/Wet Limestone Scrubber
  b. Dual Alkali Wet Scrubber
  c. Spray Dry Absorber
  d. Dry-Sorbent Injection
  e. Circulating Dry Scrubber
  f. Hydrated Ash Re-injection (HAR)
vi. CFB Boiler with Low-Sulfur Coal and Coal Cleaning
vii. CFB Boiler with Low-Sulfur Coal and FGD
viii. CFB Boiler with Low-Sulfur Coal Limestone Injection
ix. CFB Boiler with High or Low-Sulfur Coal, Coal Cleaning, and FGD
x. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, and Coal Cleaning
xi. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, and FGD
xii. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, Coal Cleaning, and FGD

The following text provides a brief overview of the above-cited SO_2 control options/technologies/strategies that have been evaluated for the proposed project.

i. CFB Boiler with High-Sulfur Coal

SO_2 emissions from a CFB Boiler with no control are strictly dependent on the sulfur content of the coal being fired. The coal for a CFB Boiler is crushed to a specific size and injected into the CFB Boiler. The coal mixes with the bed material and circulates through the boiler until all of the coal is combusted. The bed material can be made up of stone, sand, and/or limestone. The use of limestone as a bed material is a common industry practice as a first stage SO_2 control strategy.

ii. CFB Boiler with Low-Sulfur Coal (Fuel Blending or Switching)

Another potential control option for reducing SO_2 emissions is to reduce the amount of sulfur contained in the coal by using low-sulfur coal (e.g., current project proposal) or by blending low-sulfur coal with relatively higher sulfur coal (e.g., Midwestern United States bituminous coal). Low-sulfur coal is used as a means to decrease the SO_2 emissions without installing SO_2 add-on control devices. By blending low sulfur coal with high sulfur coal or by switching from high sulfur coal to a lower sulfur coal, SO_2 emissions will decrease. When low-sulfur coal is readily available, fuel blending or switching can be a cost-effective means to reduce SO_2 emissions. CFB Boilers are typically not sensitive (from an operational standpoint) to different types of coal or solid fuels. This is one of the benefits of a CFB Boiler.

iii. CFB Boiler with Limestone Injection

In a CFB Boiler, crushed limestone ($CaCO_3$) is fed to the combustor and becomes part of the solid medium that makes up the combustion bed. Within the combustion zone, lime (CaO) is formed by calcining the $CaCO_3$. SO_2 formed during the combustion process combines with the calcined CaO to form gypsum ($CaSO_4$), a stable byproduct, or $CaSO_3$ as shown in the following reactions:

$$SO_2 + CaO + \frac{1}{2}O_2 \rightarrow CaSO_4$$

or

$$SO_2 + CaO \rightarrow CaSO_3$$

The SO_2 removal equation shows that one mole of calcium is required to capture one mole of sulfur. Therefore, the theoretical minimum Ca/S ratio required for the removal of a given sulfur concentration is 1/1, assuming 100% utilization of the sorbent. However, the actual removal efficiency that can be achieved in practice for a given unit is dependent on several factors including the size and porosity of the lime, temperature of the combustion bed, residence time within the combustion bed, mixing, and uncontrolled SO_2 concentration. In practice, it has been found that approximately 50% of the SO_2 will be removed at a Ca/S ratio of 1. As the Ca/S ratio increases, a greater amount of SO_2 will be removed, but with diminishing return. Limestone injection is an integral part of the CFB Boiler process; however, the actual limestone injection rate varies from unit to unit as the sulfur in the coal or fuel varies.

iv. CFB Boiler with Coal Cleaning

Various coal cleaning processes may be employed to reduce the coal sulfur content. Physical coal cleaning removes mineral sulfur (such as pyrite) but is not effective in removing organic sulfur. Chemical cleaning and solvent refining processes are being developed to remove organic sulfur. Coal cleaning has generally been used on high mineral, high sulfur, coal for power plants without FGD systems with some success. In some studies, coal-cleaning processes have been noted to reduce the feed coal sulfur content by 1% in high sulfur coal with sulfur contents up to 5%. This equates to an approximate 20% reduction in total sulfur-in-coal. Coal cleaning requires water and/or chemicals for removing the sulfur, pyrite, and other materials; consequently, a wastewater stream is produced by the coal cleaning system, which must be treated before discharge from the facility.

v. CFB Boiler with FGD

Post-combustion methods for CFB Boilers mainly consist of FGD and are typically classified as either wet or dry systems. Wet and dry FGD are well-established SO_2 control options. Wet FGD removes SO_2 with a wet lime or limestone slurry as compared to dry FGD, which injects dry lime or limestone and produces a dry by-product that is removed with the fly ash in the particulate control device (e.g., fabric filter baghouse (FFB)). Dry FGD, as the name applies, does not use water and does not require a wastewater disposal system. The following text provides a brief overview of available FGD systems:

a. Wet Lime/Limestone Scrubber

The wet lime scrubbing process uses alkaline slurry made by adding lime (CaO) to water. The alkaline slurry is sprayed into the exhaust stream and reacts with the SO_2 in the flue gas. Insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) salts are formed in the chemical reaction that occurs in the scrubber. The salts are removed as a solid waste by-product. The waste by-product is mainly $CaSO_3$, which is difficult to dewater. Solid waste by-products from wet lime scrubbing are typically managed in dewatering ponds and landfills.

Wet limestone scrubbers are very similar to wet lime scrubbers. However, the use of limestone ($CaCO_3$) instead of CaO requires different feed preparation equipment and a higher liquid-to-gas ratio. The higher liquid-to-gas ratio typically requires a larger absorbing unit. The $CaCO_3$ slurry process also requires a ball mill to crush the $CaCO_3$ feed.

Forced oxidation of the scrubber slurry can be used with either the lime or limestone wet FGD system to produce gypsum solids instead of calcium sulfite by-product. Forced oxidation of the scrubber slurry provides a more stable by-product and reduces the potential for scaling in the FGD. The gypsum by-product may be sold for other uses, reducing the quantity of solid waste that needs to be disposed of in a landfill.

Wet lime/limestone scrubbers can achieve SO_2 control efficiencies of approximately 95% or greater when used on boilers burning higher sulfur bituminous coals, but may be less efficient when the boiler is combusting lower sulfur coals, such as that proposed for the current project. The actual control efficiency of a wet lime/limestone FGD system depends on several factors, including the uncontrolled SO_2 concentration entering the scrubber.

b. Dual Alkali Wet Scrubber

Dual-alkali scrubbers use a sodium-based alkali solution to remove SO_2 from the combustion exhaust gas. The process uses both sodium-based and calcium-based compounds. The sodium-based reagents absorb SO_2 from the exhaust gas, and the calcium-based solution (lime or limestone) regenerates the spent liquor. Calcium sulfites and sulfates are precipitated and discarded as sludge, and the regenerated sodium solution is returned to the absorber loop. The dual-alkali process requires lower liquid-to-gas ratios than scrubbing with lime or limestone. The reduced liquid-to-gas ratios generally mean smaller reaction units; however, additional regeneration and sludge processing equipment is necessary.

A sodium-based scrubbing solution, typically consisting of a mixture of sodium hydroxide, sodium carbonate, and sodium sulfite, is an efficient SO_2 control reagent. However, the high cost of the sodium-based chemicals may limit feasibility of such an installation on a generating unit size of 100 MW or larger utility boiler. In addition, the process generates a less stable sludge that can create material handling and disposal issues. The control efficiency is similar to the wet lime/limestone scrubbers at approximately 95% or greater. As with the wet lime/limestone scrubbers, control efficiencies are highly dependent upon the uncontrolled SO_2 concentration entering the scrubber.

c. Spray Dryer Absorber (SDA)

The typical SDA uses lime slurry and water injected into a tower to remove SO_2 from the combustion gases. The towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry in order to produce a relatively dry by-product. The process equipment associated with an SDA typically includes an alkaline storage tank, mixing and feed tanks, an atomizer, spray chamber, particulate control device, and a recycle system. The recycle system collects solid reaction products and recycles them back to the spray dryer feed system to reduce alkaline sorbent use. SDAs are a commonly used dry scrubbing method in large industrial and utility boiler applications. SDAs have demonstrated the ability to achieve greater than 95% SO_2 reduction. Again, control efficiencies are highly dependent upon the uncontrolled SO_2 concentration entering the scrubber.

d. Dry Sorbent Injection

Dry sorbent injection involves the injection of powdered or hydrated sorbent (typically alkaline) directly into the flue gas exhaust stream. Dry sorbent injection systems are simple systems, and generally require a sorbent storage tank, feeding mechanism, transfer line and blower, and injection device. The dry sorbent is typically injected countercurrent to the gas flow through a Venturi orifice. An expansion chamber is often located downstream of the injection point to increase residence time and contact efficiency. Particulates generated in the reaction are controlled in the system's particulate control device. SO_2 control efficiencies for dry sorbent injection systems are approximately 50%, but if the sorbent is hydrated lime, then 80% or greater removal can be achieved. These systems are commonly called lime spray dryers. Once again, control efficiencies are highly dependent upon the uncontrolled SO_2 concentration entering the scrubber.

e. Circulating Dry Scrubber

A third type of dry scrubbing system, the circulating dry scrubber (CDS), uses a circulating fluidized bed of dry hydrated lime reagent to remove SO_2. Flue gas passes through a Venturi orifice at the base of a vertical reactor tower and is humidified by a water mist. The humidified flue gas then enters a fluidized bed of powdered hydrated lime where SO_2 is removed. The dry by-product produced by this system is routed with the flue gas to the unit's particulate removal system.

f. Hydrated Ash Re-Injection (HAR) System.

The HAR process is a modified dry FGD process developed to increase utilization of un-reacted lime (CaO) in the CFB ash and any free CaO left from the furnace burning process. The hydrated ash re-injection process will further reduce the SO_2 concentration in the flue gas. The actual design of a HAR system is vendor-specific and hydrated ash re-injection type systems may be referred to as a Flash Dry Absorber™ (Alstom trade name) or a polishing scrubber.

In a hydrated ash re-injection system, a portion of the collected ash and lime is hydrated and re-introduced into a reaction vessel located ahead of the fabric filter inlet. In conventional boiler applications, additional lime may be added to the ash to increase the mixture's alkalinity. For CFB applications, sufficient residual CaO is available in the ash and additional lime is not required. It is estimated that potential SO_2 emissions would be reduced by approximately 90 to 95% in the CFB with an additional 60 to 80% reduction achieved with the addition of a HAR system. The overall control efficiency would be approximately 97% to 98% with low sulfur coal and even greater with high sulfur coal fuel.

vi. CFB Boiler with Low-Sulfur Coal and Coal Cleaning

As stated previously, coal cleaning is typically performed on high-sulfur coals. The economics of cleaning low-sulfur coal show this to be an expensive method with relatively little benefit of additional reduction in sulfur.

vii. CFB Boiler with Low-Sulfur Coal and FGD

Low-sulfur coal is typically used to reduce overall SO_2 emissions from a CFB Boiler. However, the control efficiency decreases as the inlet SO_2 decreases with a lower-sulfur coal.

viii. CFB Boiler with Low-Sulfur Coal Limestone Injection

As stated previously, limestone can be injected in the CFB Boiler as bed material, which can help reduce SO_2 emissions. Low sulfur coal would not require as much limestone injection as a high sulfur coal to achieve an equivalent SO_2 emission rate.

ix. CFB Boiler with High or Low-Sulfur Coal, Coal Cleaning, and FGD

As stated previously, coal cleaning can remove approximately 20% of the boiler SO_2 emissions. Coal cleaning is typically applied to high-sulfur coals on systems without FGD. When FGD systems are installed, coal cleaning is typically not justified due to limited additional SO_2 reduction realized for a relatively high cost.

x. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, and Coal Cleaning

As stated previously, coal cleaning is typically performed on high sulfur coals with no additional SO_2 control. The cost of cleaning coal prior to a CFB with limestone injection is expensive with relatively little benefit of reduction in SO_2 emissions through the reduction of sulfur-in-coal.

xi. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, and FGD

FGD systems can be added as a "polishing" scrubber on a CFB Boiler with limestone injection. This control option typically can remove SO_2 emissions at control efficiency greater than 97% with low-sulfur coal and can achieve higher control efficiency with a high sulfur coal. The CFB Boiler technology with low sulfur coal, limestone injection, and HAR FGD SO_2 control strategy has been proposed by SME-HGS for the project.

xii. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, Coal Cleaning, and FGD

As stated previously, coal cleaning is typically performed on high sulfur coals for use in boilers with no additional SO_2 control. The economics of cleaning coal prior to a CFB with limestone injection and FGD is expensive with very little benefit of reduction in sulfur.

B. Technical Feasibility Analysis

SME-HGS is proposing to use low sulfur coal with an average sulfur content of approximately 0.7% sulfur by weight. Therefore, although high sulfur coal is technically feasible, all control options for high sulfur coal are eliminated from further evaluation. Since coal cleaning is typically performed on high sulfur coals, and provides minimal additional benefit when performed on low sulfur coal, all control options with coal cleaning are eliminated from further evaluation.

The circulating dry scrubber has limited application, and has not been used on large CFB Boilers. Furthermore, circulating dry scrubber systems result in high particulate loading to the unit's particulate control device. Because of the high particulate loading, the pressure drop across a fabric filter would be unacceptable; therefore, electrostatic precipitators (ESP) are generally used for particulate control. For reasons further discussed in the filterable PM (filterable and condensable) BACT analysis for the CFB Boiler, the Department determined that FFB constitutes BACT for CFB Boiler particulate control. Based on limited technical data from non-comparable applications and engineering judgment, the Department determined that CDS is not technically feasible with a CFB Boiler equipped with FFB particulate control. Therefore, the CDS will not be evaluated further.

Although a dry sorbent injection system may be technically feasible, it is not practical for use with a CFB. The CFB flue gas contains excess un-reacted lime and heavy ash particles that will be re-injected back into the CFB combustion bed. A dry sorbent injection system would simply add additional unreacted lime to the flue gas. Furthermore, SO_2 control efficiencies for dry sorbent injection systems are typically around 50% on units with a much higher uncontrolled SO_2 concentration in the flue gas. If used in conjunction with a CFB unit (with a relatively low SO_2 concentration in the flue gas), the control efficiency would be expected to be something less than 50%. Because the dry sorbent injection system is not practical with a CFB, and because the control efficiency of the dry sorbent system is lower than the control efficiency of other post-combustion control options, the system will not be evaluated further.

Summary Table: SO_2 Control Option Infeasibility	
SO_2 Control Option	**Basis for Infeasibility**
All Control Options with High Sulfur Fuel	SME-HGS is proposing to use low sulfur coal
All Control Options with Low Sulfur Fuel and Coal Cleaning	Coal cleaning is considered ineffective with low sulfur coal because it is mostly organic sulfur and does not react to cleaning as well as the higher sulfur content bituminous coals.
CFB with or without Limestone Injection with Low Sulfur Coal and Dry Sorbent Injection	Not as effective an SO_2 option as dual-alkali, SDA, or hydrated ash re-injection. Eliminated from further evaluation.
CFB with or without Limestone Injection with Low Sulfur Coal and Circulating Dry Scrubber	Limited actual experience and not considered technically feasible because of the high particulate loading and excess pressure drop across a FFB.

C. Ranking of Available and Technically Feasible SO_2 Control Options by Efficiency

Wet scrubbing systems (without additional control options) are capable of removing approximately 90-95% of SO_2 emissions from higher sulfur coals. Though various reagents such as lime, limestone, or magnesium-enhanced lime all have different SO_2 removal efficiencies, overall system efficiency is maintained by operating with a slurry feed rate that is appropriate for the reagent being used. For the present analysis, the wet FGD system will be evaluated with an upstream fabric filter baghouse (FFB) followed by a wet lime scrubber. Particulate control is required upstream from the scrubber to maintain scrubber efficiency.

Dry FGD systems are reported to be capable of removing up to 95% of the SO_2 in flue gas streams resulting from combustion of high-sulfur coal. These systems must include downstream particulate control equipment since the FGD adds particulate to the gas stream. FFBs and electrostatic precipitators (ESPs) provide essentially equivalent particulate control efficiency. The dry FGD system will be evaluated with an FFB since it potentially enhances SO_2 and sulfuric acid mist (H_2SO_4) removal efficiency. As the exhaust gas passes through a filter cake containing alkaline ash and un-reacted reagent, additional SO_2 is removed. For this reason, the system configuration of a dry FGD in combination with an ESP will not be further evaluated for the proposed project.

The combination of a CFB Boiler with limestone injection and an FGD can have an overall SO_2 control efficiency of approximately 97% to 98%. This level of collection efficiency is achieved due to the reaction time allowed for the lime in both the CFB furnace as well as the FGD.

Summary Table: SO_2 Control Option Rank by Efficiency		
SO_2 Control Option	**Emission Rate (lb/MMBtu)[a]**	**SO_2 Control Efficiency**
CFB with Limestone Injection, Low Sulfur Coal, and Wet Lime/Limestone Scrubber	0.038	97.3%
CFB with Limestone Injection, Low Sulfur Coal, and Dual-Alkali Wet Scrubber	0.038	97.3%
CFB with Limestone Injection, Low Sulfur Coal, and Spray Dry Absorber	0.038	97.3%
CFB with Limestone Injection, Low Sulfur Coal, and Hydrated Ash Reinjection	0.038	97.3%
CFB with Limestone Injection, Low Sulfur Coal (Fuel Blending or Switching)	0.08	94.4%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal and Wet Lime Scrubber	0.10	93%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal and Wet Limestone Scrubber	0.10	93%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal and Dual-Alkali Wet Scrubber	0.16	88.7%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal and Spray Dry Absorber	0.16	88.7%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal and Dry Sorbent Injection	0.80	43.7%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal (without control)	1.42	---
[a] Based on a 30-day rolling average		

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following paragraphs evaluate environmental, economic, and energy impacts associated with the remaining SO_2 control options on a CFB Boiler with limestone injection. All control options/strategies without limestone injection have been eliminated from further BACT consideration because SME-HGS proposed limestone injection technology and because a CFB Boiler with limestone injection represents greater SO_2 control efficiency when compared to CFB without limestone injection.

i. Environmental Impacts

Wet FGD systems emit some level of mist that poses negative environmental impacts related to acid gas emissions (H_2SO_4, HCl, and HF), fine particulate emissions, and near and far-range visibility degradation. Dry FGD systems avoid these problems because the technology does not produce mist and because emissions from the absorber must pass through a filter cake of alkaline material collected in the downstream FFB before exhausting to the atmosphere. Another negative environmental impact associated with a wet FGD system is related to water usage. A wet FGD system uses approximately 20% more water than a dry FGD.

Both wet and dry systems produce solid waste streams containing fly ash and spent lime or limestone and these wastes are generally disposed of in a landfill area or stored in surface impoundments. The wet dual-alkali system uses sodium-based chemicals, which generates a less stable sludge than wet lime/limestone scrubber sludge. This can create material handling and disposal issues of concern.

Even though wet FGD systems use more water and generate a wastewater sludge, wet FGD systems cannot be eliminated from further investigation under the BACT analysis and are thereby evaluated further for economic and energy impacts. The dual-alkali wet scrubber will be eliminated from further investigation due to the material handling and disposal issues (e.g., leachate polluting the ground water causing long-term storage issues) associated with the sludge byproducts.

ii. Economic Impacts

Department verified economic impacts associated with CFB Boilers for each of the above FGD systems were compared in the SME-HGS application using estimated annualized capital, operating, and maintenance costs. Cost estimates were provided from commercial suppliers of this type of equipment. Where appropriate, constant operation and maintenance factors were identified and applied consistently to control options. As reported in the application, the cost effective value for CFB with limestone injection, low-sulfur coal, and wet lime/limestone scrubber is approximately \$27,365/ton SO_2 removed; the cost effective value for CFB with limestone injection, low sulfur coal, and SDA is approximately \$7939/ton SO_2 removed; and the cost effective value for CFB with limestone injection, low sulfur coal, and HAR is approximately \$4,054/ton SO_2 removed. Based on the cost-effective values provided above, CFB with limestone injection, low sulfur coal, and HAR is deemed economically feasible for the affected unit and all other control options are deemed economically infeasible for the affected unit in this case. A detailed cost analysis is included in the application for this air quality permit.

iii. Energy Impacts

Both wet and dry FGD systems require electricity to operate. The wet FGD system uses electricity primarily for the ID fan, re-circulation pumps, reagent handling, and for wet waste dewatering. The dry FGD uses electricity primarily for the ID fan, lime/limestone handling equipment and FFB blowers. Wet FGD system power consumption is approximately 40% greater than that of the dry FGD system. With a HAR system, there is no recirculation pump, wet waste dewatering and reduced power consumption for the reagent (lime/limestone) handling system. None of the control options are eliminated based on energy impacts.

E. SO_2 BACT Determination

SME-HGS proposed the use of CFB Boiler technology with limestone injection, low sulfur coal, and HAR, to maintain compliance with a proposed SO_2 BACT emission limit of 0.038 lb/MMBtu (30-day average). Based on Department verified information contained in the SME-HGS application for Permit #3423-00 and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed SO_2 emission control strategy and emission limit constitute BACT in this case. This BACT determined control option constitutes an approximate 97% SO_2 reduction efficiency.

Other recent SO_2 BACT determinations for coal-fired power plants were researched in the RACT/BACT/LAER Clearinghouse (RBLC) and Western US agency websites. The Department verified data from these websites is summarized in the application. The SME-HGS BACT determined SO_2 emission limit is at the low end of all other recently permitted similar source SO_2 BACT determinations, world-wide. The only facilities with permitted and BACT determined SO_2 emission limits lower than SME-HGS are the AES facility in Puerto Rico and the proposed NEVCO facility in Utah. The applicable SO_2 BACT emission limit for both of these facilities is 0.022 lb/MMBtu. To the best of the Department's knowledge, as of the date of permit issuance, compliance with the applicable SO_2 BACT emission limit had not been demonstrated at the AES facility or the NEVCO facility.

The Department determined that the CFB Boiler operating under the BACT determined control requirements is capable of meeting the established SO_2 BACT emission limit of 0.038 lb SO_2/MMBtu (30-day average). Further, the Department determined that the periodic SO_2 source testing, the applicable provisions contained in the Acid Rain Program (40 CFR 72-78), applicable continuous monitoring, and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted SO_2 BACT limit(s).

2. Filterable PM Emissions

Particulate matter emissions consist of filterable and condensable particulate. Filterable PM resulting from the proposed SME-HGS project is comprised of ash from the combustion of fuel, noncombustible metals present in the fuel, and unburned carbon resulting from incomplete combustion. Filterable PM is material that is in particulate form within the boiler stack and thus collects on the filter of a particulate sampling train. Condensable particulates include condensable organic compounds and minerals (in vapor form) that pass through the filter on a sampling train and are collected in glass impingers that contain a chilled wet solution to condense the vapors from the exhaust stream.

This BACT analysis focuses on control technologies for filterable PM. PM_{10} (filterable and condensable) is addressed later in the BACT analysis for the proposed project (see PM_{10} (filterable and condensable) BACT Analysis and Determination).

A. Identification of Available Filterable PM Control Strategies/Technologies

Several techniques can be used to reduce filterable PM emissions from fossil fuel combustion. Three of the most commonly available and effective methods for control of filterable PM emissions are listed below:

i. Wet scrubbers,
ii. Electrostatic precipitators (ESP), and
iii. Fabric filter baghouses (FFB)

The above-cited control strategies and/or combinations thereof, as detailed in the following table, can be used to effectively control filterable PM/PM_{10}.

Summary Table: Available Filterable PM Control Options		
Emitting Unit	**Control Option**	**Combined Control Option**
CFB Boiler	Wet or Dry ESP	Wet Scrubber with Wet ESP
	FFB with Fiberglass Bags	
	FFB with Specialty Bags	Wet Scrubber with FFB
	Wet/Dry Scrubber	

A general description of the ESP, FFB, and wet scrubber control technologies is described below. Only the control device is described, not each control option listed above.

i. Wet Scrubbers

Wet scrubbers typically use water to impact, intercept, or diffuse a particulate-laden gas stream. With impaction, particulate matter is accelerated and impacted onto a surface area or into a liquid droplet through devices such as venturi or spray chamber. When using interception, particles flow nearly parallel to the water droplets, which allow the water to intercept the particles. Interception works best for submicron particles. Spray-augmented scrubbers and high-energy venturi employ this mechanism. Diffusion is used for particles smaller than 0.5 micron and where there is a high temperature difference between the gas and the scrubbing liquid. The particles migrate through the spray along lines of irregular gas density and turbulence, contacting droplets of approximately equal energy.

Six particulate scrubber designs are used in wet scrubber control applications: spray, wet dynamic, cyclonic spray, impactor, Venturi, and augmented. In all of these scrubbers, impaction is the main collection mechanism for particles larger than 3 microns. Since smaller sized particles respond to non-inertial capture, a high density of small liquid droplets is needed to trap the particles. This is done at the price of high-energy consumption due to hydraulic or velocity pressure losses (William Vatavuk, *Estimating Costs of Air Pollution Control*, 1990). Wet scrubbers used specifically for particulate control are not commonly used on large utility boilers because of the high pressure drop to remove particulate to levels equivalent to those achieved with an FFB or ESP. Wet scrubbers are commonly designed for SO_2 removal instead of particulate control.

ii. ESP

An ESP is a particulate control device that uses electric forces to move particles out of the gas stream and onto collector plates. The particles are given an electric charge by forcing them to pass through the corona that surrounds a highly charged electrode, frequently a wire. The electrical field then forces the charged particles to the opposite charged electrode, usually a plate. Solid particles are removed from the collection electrode by a shaking process know as “rapping.” ESPs may be configured in several ways including the plate wire precipitator, the flat plate precipitator, the tubular precipitator, the wet precipitator, and the two-stage precipitator. These descriptions are outlined in the EPA *OAQPS Cost Control Manual* for ESP control.

The plate wire precipitator is the most common variety. It is commonly installed on coal fired boilers, cement kilns, solid waste incinerators, paper mill recovery boilers, petroleum refining catalytic cracking units, sinter plants, and different varieties of furnaces. Plate wire precipitators are designed to handle large volumes of gas. The flat plate precipitator is designed to use flat plates instead of wires for high-voltage electrodes. Small particle sizes with low-flow velocities are ideal for the flat plate precipitator. The flat plate precipitator usually handles gas flows ranging from 100,000 to 200,000 actual cubic feet per minute (acfm). Tubular precipitators are typically parallel tubes with electrodes running along the axis of the tubes. Tubular precipitators have typical applications in sulfuric acid plants, coke oven byproduct gas cleaning, and steel sinter plants. Wet precipitators can be any of the three previously discussed precipitators but with wet collection plates instead of dry collection plates. A wet precipitator aids in further collection of particles by preventing the collected ash from being re-entrained in the exhaust stream during the rapping of the walls, a problem common to dry precipitators. The disadvantages are the complexity of handling the wash and disposal of the slurry.

Finally, two-stage precipitators are parallel in nature (i.e., the discharge and collecting electrodes are side by side). Two-stage precipitators are designed for indoor applications, low gas flows below 50,000 acfm, and submicrometer sources emitting oil mists, smokes, fumes, and other sticky particulates. Two-stage systems are specialized types of devices that are very limited in applications.

Dry ESPs may be used downstream of a dry FGD unit to collect the dry FGD media and the ash formed during fuel combustion. However, they do not enhance SO_2 or SO_3 control. Dry ESPs are not suited for use downstream of wet FGD systems due to the high moisture content of the gas stream and the resulting stickiness of the particles. Wet ESPs may be used downstream of a wet FGD unit to capture both residual flue gas particulate and H_2SO_4 that may have formed in the wet FGD unit.

iii. FFB

FFBs consist of one or more isolated compartments containing rows of fabric filter bags or tubes. The exhaust stream passes through the fabric where the filterable particulate is retained on the upstream face of the bags, while the cleaned gas stream is vented to the atmosphere or to another pollution control device. FFBs collect particle sizes ranging from submicron to several hundred microns at gas temperatures up to approximately 500°F. Specialty bags can be used to achieve lower particulate emission rates or with stack temperatures above 500°F. FFBs can be categorized by the types of cleaning devices (shaker, reverse-air, and pulse-jet), direction of the gas flow, location of the system fan, and/or the gas flow quantity. Typically, the type of cleaning method distinguishes the FFB.

Advantages to FFBs are the high collection efficiency (in excess of 99%) and the collection of a wide range of particle sizes. The operational disadvantages of FFBs are limits on gas stream temperatures above 500°F (for typical installations), high-pressure drops, wet gas streams, and issues resulting from gas or particles that are corrosive and/or sticky in nature.

FFBs are not used downstream of a wet FGD system due to the high moisture content of the exhaust gas, which will saturate and ultimately plug the fabric filters. When used downstream of a dry FGD system, the FFB provides additional sulfur oxide control. The alkaline filter cake continues to react with and remove gaseous SO_2 and SO_3 as they pass through the filters. The alkaline filter cake also captures acid gas mist that may have formed in the exhaust system.

B. Technical Feasibility Analysis

Wet scrubbers designed for particulate control are technically infeasible on large utility boilers because of the high-pressure drops. FFB and ESP particulate control devices are commonly used on large utility boilers and are examined further for BACT applicability.

C. Ranking of Available and Technically Feasible Filterable PM/PM_{10} Control Options by Efficiency

FFBs and ESPs have proven capabilities in removing greater than 99% of the filterable PM from the exhaust gas stream generated by processes similar to the SME-HGS CFB Boiler. FFBs are generally specified for use downstream of a dry FGD system. The following table ranks the filterable PM control efficiency for the specified control options.

Summary Table: Filterable PM Control Option Rank by Efficiency

Filterable PM/PM_{10} Technology	Emission Rate (lb/MMBtu)	Estimated Control Efficiency
CFB with FFB with Teflon-Coated Bags	0.012	99.85%
CFB with FFB with Fiberglass Bags	0.015	99.81%
CFB with ESP	0.018	99.77%
CFB with No Add-on Control	7.78	---

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following paragraphs evaluate environmental, economic, and energy impacts associated with the Filterable PM control options on a CFB Boiler with limestone injection.

i. Environmental Impacts

The predominant environmental impact from controlling particulate in an FFB or ESP is related to the fly ash that is collected. The fly ash needs to be properly handled and deposited. SME-HGS is proposing to dispose the fly ash and bed ash in an on-site monofill. Further, an ESP does not provide the additional co-benefit SO_2/SO_3 collection due to the alkaline filter cake on the bags, but has not been eliminated based on environmental impacts.

ii. Economic Impacts

Department verified economic impacts associated with filterable particulate control options were compared in the SME-HGS application using estimated annualized capital, operating, and maintenance costs. Where appropriate, constant operation and maintenance factors were identified and applied consistently to control scenarios. Department verified and detailed information regarding economic impacts is contained in the application for this air quality permit.

The annual operating cost for Teflon-coated bags is approximately $500,000 more than the operating cost for standard fiberglass bags. The increase in annual cost is mainly associated with more expensive bags, and a smaller portion of the annual cost increase is associated with additional operating and maintenance costs. Despite the increase in costs associated with the use of Teflon-coated bags, the Department determined that an emission limit of 0.012 lb/MMBtu represents an achievable and cost-effective limit. As reported in the application, the annual cost-effective value for Teflon-coated bags for the proposed project is approximately $83/ton filterable PM removed as compared to approximately $78/ton filterable PM removed using standard fiberglass bags. Based on the cost-effective values provided above, all control options are deemed economically feasible for the affected unit in this case. A detailed cost analysis is included in the application for this air quality permit.

iii. Energy Impacts

Each of the control options require power in the form of fan horsepower to overcome the control device pressure drop. However, energy impacts do not eliminate any of the control options.

E. Filterable PM BACT Determination

SME-HGS proposed the use of FFB to maintain compliance with a proposed filterable PM BACT emission limit of 0.015 lb/MMBtu. Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed FFB PM control strategy constitutes BACT in this case. However, the Department determined that the proposed emission limit of 0.015 lb/MMBtu does not constitute BACT in this case.

The FFB provides better particulate control than an ESP, is widely used in the coal-fired power generation industry, and was analyzed and is required as part of the SO_2 BACT control determination. An FFB on a CFB with limestone injection and HAR provides a co-benefit of SO_2/SO_3 control, whereas an ESP does not provide this co-benefit control.

The Department determined that maintaining compliance with a limit of 0.012 lb/MMBtu constitutes BACT in this case. In the BACT analysis contained in the application, SME-HGS states that discussions with baghouse manufacturers and vendors indicates a limit of 0.012 lb/MMBtu will not be guaranteed without significant increases in costs in order to cover any risks associated with performance guarantees and liquidated damages. However, the Department determined that the cost-effective values incurred by SME-HGS in order to meet a filterable PM emission limit of 0.012 lb/MMBtu are well within industry norms and constitute BACT in this case. Further, the Department determined that the BACT-determined FFB is capable of reducing visible emissions from the CFB Boiler stack to a level that will not exceed 20% opacity averaged over 6 consecutive minutes except for one 6-minute period per hour of not greater than 27% opacity. The Department determined that these opacity limits constitute BACT in this case.

Further, the BACT determined filterable PM emission limit and opacity limits are consistent with the values reported in the RBLC for other recently permitted and similar sources, including recently permitted sources permitted and operating in Montana. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT determined control requirements is capable of meeting the established filterable PM BACT emission limit of 0.012 lb/MMBtu and 33.25 lb/hr (0.012 lb/MMBtu * 2770.6 MMBtu/hr average boiler heat input capacity) and the visible emissions standard of less than 20% opacity averaged over 6 consecutive minutes except for one 6-minute period per hour of not greater than 27% opacity. Further, the Department determined that the periodic filterable PM source testing, continuous opacity monitoring, and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted filterable PM and opacity BACT limit(s).

3. NO_x Emissions

NO_x is formed by thermal oxidation of nitrogen in the combustion air and by oxidation of nitrogen in the fuel. Thermal NO_x is formed in the high temperature region of the flame or combustion zone of the affected combustion unit. The major factors influencing thermal NO_x formation are temperature, residence time within the combustion zone, and concentration of nitrogen and oxygen in the inlet air. The amount of fuel NO_x formed is wholly dependent on the amount of nitrogen compounds contained in the fuel.

A. Identification of Available NO_x Control Strategies/Technologies

Applicable NO_x control technologies can be divided into two main categories: combustion controls, which limit NO_x production, and post-combustion controls, which destroy NO_x after formation.

The following specific add-on technologies were identified as having the potential to reduce NO_x emissions from a CFB Boiler:

Emitting Unit	Individual Control Options	Dual Combined Control Options
CFB Boiler	Low Excess Air (LEA)	Combination of LEA, FGR, OFA, and LNB
	Flue Gas Recirculation (FGR)	
	Overfire Air (OFA)	Combination of LEA, FGR, OFA, and/or LNB and SCR
	Low NOx Burners (LNB)	
	Selective Catalytic Reduction (SCR)	Combination of LEA, FGR OFA, and/or LNB and SNCR
	Selective Non-Catalytic Reduction (SNCR)	

A general description of the NO_x control options listed in the table above is described in the following text. Only the control device/strategy is described, not each control option listed above.

i. Low Excess Air (LEA)

LEA operation involves lowering the amount of combustion air to the minimum level compatible with efficient and complete combustion. Limiting the amount of air fed to the furnace reduces the availability of oxygen for the formation of fuel NO_x and lowers the peak flame temperature, which inhibits thermal NO_x formation.

Emissions reductions achieved by LEA are limited by the need to have sufficient oxygen present for flame stability and to ensure complete combustion. As excess air levels decrease, emissions of CO, hydrocarbons and unburned carbon increase, resulting in lower boiler efficiency. Other impediments to LEA operation are the possibility of increased corrosion and slagging in the upper boiler because of the reducing atmosphere created at low oxygen levels. This option cannot be utilized on CFB due to the level of air needed to fluidize the bed.

ii. Flue Gas Recirculation (FGR)

FGR is a flame-quenching technique that involves recirculating a portion of the flue gas from the economizers or the air heater outlet and returning it to the furnace through the burner or windbox. The primary effect of FGR is to reduce the peak flame temperature through absorption of the combustion heat by relatively cooler flue gas. FGR also serves to reduce the O_2 concentration in the combustion zone. This option can not utilized on CFB due to the level of air needed to fluidize the bed.

iii. Overfire Air (OFA)

OFA allows staged combustion by supplying less than the stoichiometric amount of air theoretically required for complete combustion through the burners. The remaining necessary combustion air is injected into the furnace through overfire air ports. Having an oxygen-deficient primary combustion zone in the furnace lowers the formation of fuel NO_x. In this atmosphere, most of the fuel nitrogen compounds are driven into the gas phase. Combustion occurring over a larger portion of the furnace lowers peak flame temperatures. Use of a cooler, less intense flame limits thermal NO_x formation.

Poorly controlled OFA may result in increased CO and hydrocarbon emissions, as well as unburned carbon in the fly ash. These products of incomplete combustion result from a decrease in boiler efficiency. OFA may also lead to reducing conditions in the lower furnace that in turn may lead to corrosion of the boiler. This option cannot be utilized on CFB due to the level of air needed to fluidize the bed.

iv. Low NO_x Burners (LNB)

LNB integrate staged combustion into the burner creating a fuel-rich primary combustion zone. Fuel NO_x formation is decreased by the reducing conditions in the primary combustion zone. Thermal NO_x is limited due to the lower flame temperature caused by the lower oxygen concentration. The secondary combustion zone is a fuel lean zone where combustion is completed. LNB may result in increased CO and hydrocarbon emissions, decreased boiler efficiency, and increased fuel costs. This option cannot be utilized on CFB due to the level of air needed to fluidize the bed.

v. Selective Catalytic Reduction (SCR)

SCR is a post-combustion gas treatment technique that uses a catalyst to reduce NO and NO_2 to molecular nitrogen and water. Ammonia (NH_3) is commonly used as the reducing agent. The basic reactions are:

$$4\ NH_3 + 4\ NO + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$8\ NH_3 + 6\ NO_2 \rightarrow 7\ N_2 + 12\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Ammonia is vaporized and injected into the flue gas upstream of the catalyst bed, and combines with NO_x at the catalyst surface to form an ammonium salt intermediate. The ammonium salt intermediate then decomposes to produce elemental nitrogen and water. The catalyst lowers the temperature required for the chemical reaction between NO_x and ammonia.

Technical factors that impact the effectiveness of this technology include the catalyst reactor design, operating temperature, type of fuel fired, sulfur content of the fuel, design of the ammonia injection system, and the potential for catalyst poisoning. SCR has been demonstrated to achieve high levels of NOx reduction in the range of 80% to 90% control for a wide range of industrial combustion sources, including PC and stoker coal-fired boilers and natural gas-fired boilers and turbines. SCR has not been demonstrated on a CFB Boiler in the United States. Typically, installation of the SCR is upstream of the particulate control device (e.g., baghouse). However, calcium oxide (from a dry scrubber) in the exhaust stream can cause the SCR catalyst to plug and foul, which would lead to an ineffective catalyst. SCRs are classified as a low or high dust SCR. A low dust SCR is usually applied to natural gas combustion units or after a particulate control device. High dust SCR units can be installed on solid fuel combustion units before the particulate control device. However, a high dust SCR cannot be installed on a CFB Boiler prior to the particulate control device because the high alkaline particulate will contaminate and possibly plug the catalyst. Therefore, the exhaust stream after a particulate control device on a CFB Boiler would need to be reheated to maintain an effective operating temperature of the catalyst.

vi. Selective Non-Catalytic Reduction (SNCR)

SNCR involves the non-catalytic decomposition of NO_x to nitrogen and water. A NO_x reducing agent, typically ammonia or urea, is injected into the upper reaches of the furnace. Because a catalyst is not used to drive the reaction, temperatures of 1600°F to 2100°F are required. The basic reactions are:

Ammonia: $4\ NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$
Urea: $CO(NH_2)_2 + 2NO + \frac{1}{2}O_2 \rightarrow 2N_2 + CO_2 + H_2O$

Typical NO_x control efficiencies range from 40% to 60% depending on inlet NO_x concentrations, fluctuating flue gas temperatures, residence time, amount and type of nitrogenous reducing agent, mixing effectiveness, acceptable levels of ammonia slip, and presence of interfering chemical substances in the gas stream. SNCR has been applied to a number of different types of combustion sources. SNCR has been widely implemented for NO_x control on new coal-fired CFBs throughout the United States.

B. Technical Feasibility Analysis

LNB, OFA, LEA, and FGR are used to reduce flame temperature and reduce the thermal NO_x; therefore, these control options separately or in combination with another control option, including SCR and SNCR, are technically ineffective on a CFB Boiler that has inherently low combustion temperatures and relatively lower thermal NO_x emissions. These control options separately or in combination with another control option including SCR and SNCR are technically infeasible. The remaining NO_x control options cannot be eliminated based on technical infeasibility.

C. Ranking of Available and Technically Feasible NO_x Control Options by Efficiency

Various information sources evaluated by the Department through the NO_x BACT analysis process assigned varying NO_x control efficiencies for each of the identified available NO_x control technologies/strategies. The following analysis uses the average of expected control efficiencies reported for each strategy:

NO_x Control Option	**NO_x Emission Rate (lb/MMBtu)**	**Estimated NO_x Control Efficiency**
CFB Boiler with SCR	0.014	90.00%
CFB Boiler with SNCR	0.07	50.00%
CFB Boiler without Controls	0.14	0.00%

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following text evaluates the environmental, economic, and energy impacts associated with the NO_x control options on a CFB Boiler.

i. Environmental Impacts

The environmental impacts from both SCR and SNCR result from the handling of the anhydrous ammonia. Spent catalyst from an SCR will have to be properly disposed as a possible hazardous waste. An SCR unit would have to be installed downstream of the baghouse to reduce fouling of the catalyst.

Therefore, as an example, natural gas would have to be used to reheat the exhaust gas to optimal temperature for the SCR unit. The combustion of the natural gas would cause additional NO_x, CO, VOC, and PM_{10} emissions into the atmosphere. Even though there are environmental concerns associated with SCR and SNCR, these NO_x control options cannot be eliminated based on these concerns.

ii. Energy Impacts

SCR would cause significant backpressure in the CFB Boiler leading to lost boiler efficiency and, thus, a loss of power production. Along with the power loss, SME-HGS would be subject to the additional cost of reheating the exhaust gas, which would be expensive at the current price of natural gas. The energy impacts from an SNCR are minimal and an SNCR does not cause a loss of power output from the facility. Even though these are energy impact concerns, the control options cannot be eliminated based on these concerns. The impacts of additional cost due to reheating the exhaust gas are included in the annual cost of operating an SCR unit, which is presented in the economic impact analysis.

iii. Economic Impacts

Department verified economic impacts associated with NO_x control options were compared in the SME-HGS application using estimated annualized capital, operating, and maintenance costs. Cost estimates for SCR and SNCR were derived from Chapter 4 in the *OAQPS COST Control Manual* (EPA 452/B-02-001). Where appropriate, assumptions were made from suggested/typical data that were supplied in the manual, and if data was not available from the manual, best engineering judgment was used. As reported in the application, the cost effective value for SNCR is approximately $2137/ton of NO_x removed and the cost effective value for SCR is approximately $12,562/ton of NO_x removed. Based on the cost-effective values provided above, SNCR is deemed economically feasible for the affected unit and SCR is deemed economically infeasible for the affected unit in this case. A detailed cost analysis is included in the application for this air quality permit.

E. NO_x BACT Determination

SME-HGS proposed the use of SNCR to maintain compliance with a proposed NO_x BACT emission limit of 0.07 lb/MMBtu (30-day rolling average). Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed NO_x emission control strategy and emission limit constitute BACT in this case. This BACT determined control option will provide an approximate 90% NO_x reduction efficiency.

SCR was eliminated based on the high cost per ton of NO_x removed. Further, since the SCR unit would have to be installed downstream from the permitted and BACT determined FFB to eliminate fouling and excessive loading of the catalyst, the CFB exhaust gas would need to be reheated. Reheating the exhaust gas is a significant factor in the high annual cost of SCR and leads to a substantial increase in emissions from the reheat process summarized. Finally, the Department is unaware of any CFB Boiler permitted or in operation in the United States, which has an SCR unit installed for NO_x emission control.

The BACT determined NO_x emission limit is equal to the lowest NO_x BACT emission rates contained in the RBLC. Further, two of the boilers permitted with NO_x BACT emission limits of 0.07 lb/MMBtu, respectively, are CFB Boilers that employ SNCR. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established NO_x BACT emission limit of 0.07 lb NO_x/MMBtu (30-day rolling average). Further, the Department determined that the periodic NO_x source testing, continuous NO_x emission monitoring, and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted NO_x BACT limit(s).

4. CO Emissions

CO emissions from a CFB coal-fired boiler are typically controlled using proper design and combustion techniques. Typical CO control technologies (e.g., catalytic and thermal oxidizers) are available; however, they are not typically considered appropriate for coal-fired boilers because of high particulate loading, catalyst fouling, and/or high cost to reheat the exhaust gas.

A. Identification of Available CO Control Strategies/Technologies

The following control options are evaluated as available CO control options for the proposed SME-HGS project:

i. CFB Boilers with Proper Design and Combustion (no add-on control); and
ii. CFB Boilers Catalytic or Thermal Oxidizers.

The following text provides a brief overview of the above-cited CO control options/technologies/strategies that have been evaluated for the proposed project.

i. Proper Design and Combustion (No Add-On Control)

In an ideal combustion process, all of the carbon and hydrogen contained within the fuel is oxidized to carbon dioxide (CO_2) and water (H_2O). The emission of CO in a combustion process is the result of incomplete fuel combustion. Reduction of CO emissions can be accomplished by controlling the combustion temperature, residence time, and available oxygen. Normal combustion practice at the facility will involve maximizing the heating efficiency of the fuel in an effort to minimize fuel usage. This efficiency of fuel combustion will also minimize CO formation.

ii. Catalytic or Thermal Oxidation of Post-Combustion Gases

Oxidizers or incinerators use heat to destroy CO in the gas stream. Incineration is an oxidation process that ideally breaks down the molecular structure of an organic compound into carbon dioxide and water vapor.

Temperature, residence time, and turbulence of the system affect CO control efficiency. A thermal incinerator generally operates at temperatures between 1,450 and 1,600ºF. Heat recovery between 35% and 70% can be realized with recuperative systems and up to 95% can be realized with regenerative systems. The thermal oxidation system analyzed for the main boiler is a regenerative thermal oxidation (RTO) system with 95% heat recovery. Regenerative systems are typically designed for exhaust flow rates between 10,000 and 100,000 standard cubic feet per minute (scfm). Recuperative systems are typically designed for exhaust flow rates between 500 and 50,000 scfm. Regenerative systems typically have higher capital costs than recuperative systems, but capital costs are typically offset by savings on auxiliary fuel use.

Catalytic incineration is similar to thermal incineration; however, catalytic incineration generally allows for oxidation at temperatures ranging from 600 to 1,000ºF and can achieve up to 70% heat recovery. The catalyst systems are typically metal oxides such as nickel oxide, copper oxide, manganese dioxide, or chromium oxide. Noble metals such as platinum and palladium may also be used. Fixed bed or fluid bed catalytic incinerators can be used on combustion exhaust streams and can achieve up to 70% heat recovery. A fixed bed catalytic incinerator with 70% heat recovery is examined in this BACT analysis because of its comparatively lower capital cost.

B. Technical Feasibility Analysis

For the purposes of this BACT analysis, proper design and combustion control and catalytic and thermal oxidation are considered technically feasible, although oxidation is not typically applied to coal-fired boilers. No available CO control options are eliminated due to technical infeasibility.

C. Ranking of Available and Technically Feasible CO Control Options by Efficiency

Various information sources evaluated by the Department through the CO BACT analysis process assigned varying CO control efficiencies ranging from 70% control for good combustion practices to 95% for the CO oxidation control technologies/strategies. To be conservative, the SME-HGS application considered 90% control efficiency for the top oxidation control. The following table ranks the CO control options.

CO Control Option	**CO Emission Rate (lb/MMBtu)**	**Estimated Control Efficiency**
CFB Boiler with Thermal Oxidation	0.01	90%
CFB Boiler with Catalytic Oxidation	0.01	90%
CFB Boiler with Proper Design and Combustion Practices (no add-on control)	0.10	---

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following text evaluates the environmental, economic, and energy impacts associated with the CO control options on a CFB Boiler.

i. Environmental Impacts

Catalytic oxidation results in adverse environmental impact from the handling of the spent catalyst and may have to be disposed of as a hazardous waste. A catalytic oxidation unit would have to be installed downstream of the FFB to reduce fouling of the catalyst; therefore, the exhaust gas would require reheating to achieve optimal CO reduction. The combustion of the additional fuel for reheating purposes would cause an increase in NO_x, SO_2, CO, VOC, and PM_{10} emissions. However, the control options cannot be eliminated based on these concerns alone.

ii. Energy Impacts

The additional consumption of fuel to reheat the exhaust gas would result in energy impacts. With current market prices for fuel, this strategy would also be very expensive. Even though these energy impacts exist, the control options cannot be eliminated based on these concerns.

iii. Economic Impacts

Department verified economic impacts associated with CO control options were compared in the SME-HGS application using estimated annualized capital, operating, and maintenance costs. Cost estimates for catalytic or thermal oxidation were derived from Section 3, Chapter 2 (9/2000) in the *OAQPS COST Control Manual*. Where appropriate, assumptions were made from suggested/typical data that were supplied in the manual and if data was not available from the manual, best engineering judgment was used. As reported in the application, the cost effective value for thermal oxidation is approximately $6916/ton of CO removed and the cost effective value for catalytic oxidation is approximately $4373/ton of CO removed. Based on the cost-effective values provided above, all control options are deemed economically infeasible for the affected unit in this case. A detailed cost analysis is included in the application for this air quality permit.

E. CO BACT Determination

SME-HGS proposed the use of good combustion practices with no additional control to maintain compliance with a proposed CO BACT emission limit of 0.10 lb/MMBtu (1-hr average). Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed CO emission control strategy and emission limit constitute BACT in this case.

Catalytic and thermal oxidation were eliminated based on the high cost per ton of CO removed and because the increased fuel consumption associated with reheating the gas stream would result in additional environmental impacts.

The BACT determined CO emission limit is equal to the lowest CFB Boiler CO BACT emission rates contained in the RBLC. Two non-CFB boilers listed in the RBLC have lower emission limits, but these two sources do not have a control device and rely on good combustion practices for CO control. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established CO BACT emission limit of 0.10 lb CO/MMBtu (1-hr average). Further, the Department determined that the periodic CO source testing and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted CO BACT limit(s).

5. VOC Emissions

VOC emissions from a CFB coal-fired boiler are typically controlled using proper design and combustion techniques that were identified in the CO BACT analysis. Typical VOC control technologies (e.g., catalytic and thermal oxidizers) are available; however, they are not typically considered appropriate for coal-fired boilers because of high particulate loading, catalyst fouling, or high cost to reheat the exhaust gas.

A. Identification of Available VOC Control Strategies/Technologies

The following control options were evaluated for the CO control options and will be evaluated for the VOC control options. A description of each control technology is provided in the CO BACT analysis:

i. CFB Boilers with Proper Design and Combustion (no add-on control); and
ii. CFB Boilers with Catalytic or Thermal Oxidizers.

B. Technical Feasibility Analysis

For the purposes of this BACT analysis, proper design and combustion control, catalytic oxidation, and thermal oxidation will be considered technically feasible, although oxidation is not typically applied to coal-fired boilers. No available VOC control options are eliminated due to technical infeasibility.

C. Ranking of Available and Technically Feasible VOC Control Options by Efficiency

Various information sources evaluated by the Department through the VOC BACT analysis process assigned varying VOC control efficiencies ranging from 70% for good combustion practices to 95% for the VOC oxidation control technologies/ strategies. To be conservative, the SME-HGS application considered 90% control efficiency for the top oxidation control. The following table ranks the VOC control options.

VOC Control Option	**VOC Emission Rate (lb/MMBtu)**	**Estimated Control Efficiency**
CFB Boiler with Thermal Oxidation	0.0003	90%
CFB Boiler with Catalytic Oxidation	0.0003	90%
CFB Boiler with Proper Design and Combustion Practices (no add-on control)	0.003	---

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following text evaluates the environmental, economic, and energy impacts associated with the VOC control options on a CFB Boiler.

i. Environmental Impacts

Catalytic oxidation results in adverse environmental impact from the handling of the spent catalyst and may have to be disposed of as a hazardous waste. A catalytic oxidation unit would have to be installed downstream of the FFB to reduce fouling of the catalyst; therefore, the exhaust gas would require reheating to achieve optimal VOC reduction. The combustion of the additional fuel for reheating purposes would cause an increase in NO_x, SO_2, CO, VOC, and PM_{10} emissions. However, the control options cannot be eliminated based on these concerns alone.

ii. Energy Impacts

The additional consumption of fuel would result in energy impacts from reheating the exhaust. With current market prices for natural gas, this strategy would also be very expensive. Even though these energy impacts exist, the control options cannot be eliminated based on these concerns.

iii. Economic Impacts

Department verified economic impacts associated with VOC control options were compared in the SME-HGS application using estimated annualized capital, operating, and maintenance costs. Cost estimates for catalytic or thermal oxidation were derived from Section 3, Chapter 2 (9/2000) in the *OAQPS COST Control Manual*. Where appropriate, assumptions were made from suggested/typical data that were supplied in the manual, and, if data was not available from the manual, best engineering judgment was used. As reported in the application, the cost effective value for thermal oxidation is approximately $222,928/ton of VOC removed and the cost effective value for catalytic oxidation is approximately $142,546/ton of VOC removed. Based on the cost-effective values provided above, all control options are deemed economically infeasible for the affected unit in this case. A detailed cost analysis is included in the application for this air quality permit.

E. VOC BACT Determination

SME-HGS proposed the use of good combustion practices with no additional control to maintain compliance with a proposed VOC BACT emission limit of 0.003 lb/MMBtu (1-hr average). Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed VOC emission control strategy and emission limit constitute BACT in this case.

Catalytic and thermal oxidation were eliminated based on the high cost per ton of VOC removed and because the increased fuel consumption associated with reheating the gas stream would result in additional environmental impacts.

The BACT determined VOC emission limit is among the lowest CO BACT emission rates contained in the RBLC for PC or CFB Boiler technologies. Further, the permitted VOC BACT emission rate of 0.003 lb/MMBtu matches recently permitted VOC BACT limits permitted for operation in Montana. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established VOC BACT emission limit of 0.003 lb VOC/MMBtu (1-hr average). Further, the Department determined that the periodic VOC source testing and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted VOC BACT limit(s).

6. H_2SO_4, Acid Gases (HCl and HF), Trace Metals, and Condensable PM_{10} Emissions

Sulfuric acid mist, acid gases (primarily HF and HCl), trace metals (including lead), and condensable PM_{10} are grouped together in this BACT evaluation because these pollutants are a major component of condensable PM_{10}. Other inorganic and organic species (e.g., ammonium bisulfate and certain VOCs) can also contribute to condensable PM_{10}. Control options from a CFB boiler are typically limited to the available SO_2 and/or filterable PM/PM_{10} control options.

H_2SO_4, acid gases (HCl and HF), trace metals (including lead), and condensable PM_{10} generally form in the exhaust system of a boiler. The formation is dependent upon several factors including residence time within specific temperature ranges, flue gas moisture content, combustion conditions, and concentrations of chlorine, fluorine, and trace metals in the coal.

<u>Sulfuric Acid Mist (H_2SO_4)</u>

H_2SO_4 is typically created when SO_3 in the flue gas reacts with water. SO_3 is formed during the combustion process in a coal-fired boiler. H_2SO_4 mist in boiler flue gas generally forms in three phases as described below:

Sulfur in the boiler fuel oxidizes to form sulfur dioxide (SO_2).

$$S + O_2 \rightarrow SO_2$$

A portion of the SO_2 further oxidizes to sulfur trioxide (SO_3).

$$SO_2 + \frac{1}{2} O_2 \rightarrow SO_3$$

SO_3 reacts with water in the exhaust stream or the atmosphere to form H_2SO_4.

$$SO_3 + H_2O \rightarrow H_2SO_4$$

Because H_2SO_4 mist is created in several steps, control strategies can be approached in a variety of ways that may be applied individually or in combination. Control strategies generally focus on reducing the amount of SO_2 and SO_3 in the flue gas, capturing sulfuric acid mist aerosol particles, and controlling exhaust system conditions to limit mist formation.

Acid Gases (HCl and HF)

Acid gases can be controlled to different degrees by standard control technologies for other criteria pollutants (primarily with SO_2 and filterable PM control technologies).

Trace Metals (Including Lead)

Depending on the physical and chemical properties of a metal and boiler combustion conditions, some metals can be emitted in the gas phase, while others may be emitted as particulates and will tend to be captured either in the fly or bed ash. Metals emitted from coal combustion include: arsenic, beryllium, cadmium, chromium, manganese, and lead and based on the physical and chemical properties of these listed metals, most would be emitted as particulate matter. A smaller percentage of these metals and other metals may also be emitted as volatiles and condensable particulates.

Condensable Particulate

Condensable particulate can be controlled to different degrees by controlling the components that make up condensable particulate (H_2SO_4 mist, acid gases, volatile trace metals, etc.) with standard control technologies for other criteria pollutants (primarily SO_2 and filterable PM control technologies).

A. Identification of Available H_2SO_4, Acid Gases (HCl and HF), Trace Metals, and Condensable PM_{10} Emissions Control Strategies/Technologies

Available control technologies for H_2SO_4 mist, acid gases (HCl and HF), trace metals (including lead), and condensable PM_{10} emissions from a CFB Boiler are listed below:

i. Wet FGD;
ii. Wet FGD followed by wet ESP;
iii. Dry FGD followed by FFB or ESP; and
iv. No additional add-on control.

The following text provides a brief overview of the above-cited control options/technologies/strategies that have been evaluated for the proposed project.

i. Wet FGD

Wet FGD is limited in its ability to control H_2SO_4 mist and acid gas emissions for two reasons. First, the moisture inherent in the system, combined with the sudden cooling created by the slurry spray, tends to create sulfuric acid mist and acid gases (two significant components of condensable PM_{10}). Second, because the condensable particulates are extremely small, they are not effectively captured by the washing action of the wet FGD. A wet FGD system would be expected to control sulfuric acid mist and acid gas (including HF) emissions with efficiency less than 25%.

ii. Wet FGD Followed by Wet ESP

Wet ESPs can control H_2SO_4mist and acid gases with a very high efficiency. Not all of the SO_3 in the gas stream is converted to sulfuric H_2SO_4 mist, which results in an overall H_2SO_4 mist control efficiency for this system of approximately 90% (other acid gases will also be collected at an efficiency of

90%). Use of an FFB downstream of a wet scrubber is not technically feasible, the high moisture content of the flue gas exiting the scrubber would cause the filter cake to agglomerate, clogging the filter and making the filter cleaning extremely difficult.

iii. Dry FGD Followed by FFB or ESP

Dry FGD systems, including SDAs and fly-ash reinjection systems, are generally capable of controlling SO_3 (and H_2SO_4) and acid gases with an efficiency of at least 90%. As noted above, a particulate control device is required following a dry FGD system to collect the injected reagent particles. While ESPs and FFBs provide essentially the same level of particulate control, FFBs have the potential to enhance SO_2, SO_3, and HF removal efficiency as the exhaust gas passes through a filter cake containing alkaline ash and unreacted reagent. FFBs also have a high removal efficiency of trace metals and may provide some additional control for other acid gases.

B. Technical Feasibility Analysis

None of the identified available H_2SO_4, acid gas (HCl and HF), trace metals (including lead), and condensable PM_{10} control technologies are technically infeasible. Therefore, no available control options are eliminated at this stage.

C. Ranking of Available and Technically Feasible H_2SO_4, Acid Gas (HCl and HF), Trace Metals (including lead), and condensable PM_{10} Control Options by Efficiency

The following table summarizes the available control options, their respective potential control efficiency values, and their ranking for the purposes of this BACT analysis. Limited data is available on control efficiencies for these pollutants; therefore, the proposed CFB Boiler may not perform to the exact control efficiencies highlighted in the table.

Technology	**H_2SO_4 Control Efficiency**	**Acid Gas Control Efficiency**	**Trace Metal Control Efficiency**	**Condensable PM_{10} Control Efficiency**
Dry FGD &FFB or ESP	90%	80%	90%	90%
Wet FGD & Wet ESP	90%	90%	80%	90%
Wet FGD	25%	80%	70%	80%
No Add-On Control	---	---	---	---

The top two control alternatives potentially provide similar H_2SO_4 and condensable PM_{10} control efficiency, while the top two differ in acid gas and trace metal control efficiencies. Because SME-HGS proposes to implement one of these two top alternatives based on SO_2 and filterable PM BACT analysis, no further analysis is required for H_2SO_4, acid gases, trace metals, and condensable PM_{10} control.

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The environmental, economic, and energy impacts associated with the available H_2SO_4, acid gas, trace metals, and condensable PM_{10} control options are the same as the impacts addressed in the BACT analyses for SO_2 and filterable PM emissions. Because these control strategies have been determined to constitute BACT for SO_2 and filterable PM, no additional environmental, economic, and energy impacts will be realized through the control of H_2SO_4, acid gas, trace metals, and condensable PM_{10}, through utilization of these co-benefit control strategies.

E. H_2SO_4, Acid Gas, Trace Metals, and Condensable PM_{10} BACT Determination

$\underline{H_2SO_4}$

As previously stated, either of the two top technologies for H_2SO_4 mist control will reduce emissions by 90%. SME-HGS proposes a CFB Boiler combusting low sulfur coal with dry FGD followed by an FFB to maintain compliance with a proposed H_2SO_4 BACT emission limit of 0.0054 lb/MMBtu. Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed H_2SO_4 emission control strategy and emission limit constitute BACT in this case.

This emission rate, although not the lowest, compares favorably to similar facilities in the RBLC and is lower than the BACT-determined emissions rates for the recently permitted Gascoyne CFB Boiler and the two most recent coal-fired utilities permitted for operation in Montana. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established H_2SO_4 BACT emission limit of 0.0054 lb/MMBtu over any 1-hour time period. Further, the Department determined that the periodic source testing and the applicable recordkeeping and reporting requirements contained in the permit will adequately monitor compliance with the permitted BACT limit(s).

Acid Gases

As previously stated, either of the two top technologies for acid gas control will reduce emissions by 80% to 90%. SME-HGS proposes a CFB Boiler combusting low sulfur coal with dry FGD followed by an FFB to maintain compliance with a proposed HF BACT emission limit of 0.0017 lb/MMBtu and a proposed HCl BACT emission limit of 0.0021 lb/MMBtu. Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed emission control strategy and emission limit(s) for HF and HCl, respectively, constitute BACT in this case.

These BACT-determined acid gas emission rates, although not the lowest, compare favorably to similar facilities in the RBLC, representing an average BACT emission rate for those sources contained in the RBLC. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established HF and HCl BACT emission limits of 0.0017 lb/MMBtu and 0.0021 lb/MMBtu over any 1-hour time period, respectively. Further, the Department determined that the periodic source testing and the applicable recordkeeping and reporting requirements contained in the permit will adequately monitor compliance with the permitted BACT limit(s).

Trace Metals (including Lead)

As previously stated, either of the two top technologies for trace metals control will reduce emissions by 80% to 90%. SME-HGS proposes a CFB Boiler combusting low sulfur coal with dry FGD followed by an FFB as BACT for trace metals. SME-HGS proposes the PM_{10} emission rate as a surrogate emission limit for trace metal emissions.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established PM_{10} surrogate emission limit of 0.026 lb/MMBtu. Further, the Department determined that the periodic source testing (PM_{10}) and the applicable recordkeeping and reporting requirements contained in the permit will adequately monitor compliance with the permitted BACT limit.

PM_{10}

The PM_{10} emission rate is calculated based on the assumed components that make up the condensable PM_{10} fraction plus the BACT-determined filterable PM emission limit. The following table presents the emissions rates for the components that are assumed to make up the condensable PM_{10} fraction as well as the BACT-determined filterable PM emission rate.

Component	**Emission Rate (lb/MMBtu)**
HCl	0.0021
HF	0.0017
H2SO4	0.0054
VOC	0.0030
Ammonium Bisulfate	0.0015
Trace Metals	0.0002
Organic Condensables	0.0005
Total Condensables	**0.014**
Filterable PM	0.012
PM_{10} Limit	0.026*
* PM_{10} BACT-determined emission limit equals the condensable PM_{10} fraction plus the BACT-determined filterable PM limit	

As previously stated, either of the two top technologies for the pollutants making up the condensable PM_{10} fraction will reduce emissions by 80% to 90%. SME-HGS proposes a CFB Boiler combusting low sulfur coal with dry FGD followed by an FFB to maintain compliance with a PM_{10} emission limit of 0.026 lb/MMBtu. Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed emission control strategy and the Department-established emission limit for condensable PM_{10} constitutes BACT in this case.

The BACT-determined PM_{10} emission rate, although not the lowest, compares favorably to similar facilities in the RBLC. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established PM_{10} emission limit of 0.026 lb/MMBtu. Further, the Department determined that the periodic source testing and the applicable recordkeeping and reporting requirements contained in the permit will adequately monitor compliance with the permitted BACT limit(s).

7. Mercury Emissions

Coal contains trace levels of a variety of metals and other elements or compounds. Mercury is one of those trace elements. Emissions of mercury into the atmosphere have been identified as a health concern principally due to its capacity to react chemically with the environment to form a toxic compound – methyl mercury – that accumulates through the aquatic food chain with a potential to threaten human populations. Depending on its chemical form, mercury can persist in the atmosphere and travel vast distances before being deposited on terrestrial features.

When coal burns, mercury is released in one of three forms, or species: elemental mercury vapor, oxidized mercury vapor, or mercury adsorbed to the surface of a solid particle. The different species of mercury respond differently to different types of control technologies.

Elemental mercury is the most difficult of the three mercury species to control. To date, no technologies have been demonstrated in field-testing to consistently and significantly reduce elemental mercury emissions. Most research is focused on developing effective means for converting elemental mercury to one of the other two species of mercury.

Oxidized mercury is water soluble and generally more reactive than elemental mercury. Because of this, technologies for controlling SO_2 emissions have demonstrated promise for controlling oxidized mercury emissions as well. Research has shown a strong correlation between coal chlorine content and the proportion of oxidized mercury in coal combustion products. Under specific conditions, the addition of chlorine or other halides has been shown to promote mercury oxidation.

Particulate mercury may be controlled with FFBs and/or ESPs – devices commonly used to control particulate emissions from coal combustion processes. The proportion of particulate mercury emissions appears to be related to the amount of oxidized mercury. Oxidized mercury is more readily adsorbed to the surface of particles such as coal ash, FGD media, or activated carbon than is elemental mercury. Higher levels of unburned carbon (UBC) in the ash have also been shown to favor mercury adsorption.

<u>Department of Energy, U.S. Environmental Protection Agency, and Industry Research</u>

For the last several years the Department of Energy/National Energy Technology Laboratory (DOE/NETL) and the Electric Power Research Institute (EPRI) have evaluated mercury removal technologies for potential application to the power generation industry. However, the Department and SME-HGS have been unable to find research specifically evaluating control of mercury emissions from CFB Boilers.

A recent white paper from the EPA ("the technology review report") describes and summarizes the status of test programs throughout the country aimed at understanding and improving capabilities for reducing mercury emissions from coal-fired electric generators ("*Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update*," Air Pollution Prevention and Control Division, National Risk Management Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency; February 18, 2005). Results have varied greatly, from an actual increase of mercury emissions to over 90 percent mercury removal efficiency.

It has long been recognized that coal quality is a primary determining factor in mercury removal effectiveness. Bituminous coal generally contains higher levels of chlorine and UBC, and has therefore proven to provide enhanced capacity for mercury reduction. Conversely, subbituminous coal and lignite, often grouped as the single category of "low rank coal," generally contain low concentrations of chlorine and UBC. Control of mercury emissions resulting from combustion of these fuels has proven to be highly variable.

Mercury emissions control research, as it relates to coal-fired power generation, has followed two general paths: characterizing and enhancing co-benefits from existing control equipment (sometimes referred to as "native capture"), and development of mercury-specific control technologies. The two paths at times intermingle since mercury-specific control technologies often must be used in tandem with native capture. For example, modified or standard powdered activated carbon injection (ACI) is one of the most promising mercury-specific control technologies under certain conditions. Once injected into the exhaust stream, however, it must be captured by a particulate emissions control device. Following are some concluding observations from the EPA's technology review report:

- "Assuming sufficient RD&D of representative technologies, new and existing systems installed to control NO_x and SO_2 (e.g., SCR+FGD+FFB) have the potential to achieve 90%+ control of mercury for bituminous coal-fired boilers. Subbituminous and lignite systems appear to require mercury oxidation technology and/or additional advanced sorbents to achieve these levels."
- "It is believed that ACI and enhanced multi-pollutant controls will be available after 2010 for commercial application on most, if not all, key combinations of coal type and control technology to provide mercury removal levels between 60 and 90%. Also, optimized multi-pollutant controls may be available in the 2010-2015 timeframe for commercial application on most, if not all, key combinations of coal type and control technology to provide mercury removal levels between 90 and 95%."
- "The principle concerns relating to broad-scale use of mercury controls are the reliability of mercury reductions possible and the risks of adverse side effects. To the extent that required mercury reductions are within the capabilities of the technology with minimum risks of side effects, mercury controls could be considered available. However, as discussed in this paper, there remain some questions regarding their performance relative to broad-scale use. These questions are being investigated in ongoing efforts."

Project Coal Supply

SME-HGS is proposing to use Powder River Basin (PRB) subbituminous coal as the CFB Boiler fuel source. Specifically, SME-HGS is currently considering purchasing coal from one of the following three southeastern Montana coal mines: Spring Creek, Decker, and/or Absaloka coal mines. Coal quality data from two of these sources indicates average coal mercury content is 0.05-0.07 ppmw, compared with a national average of 0.17 ppmw ("Mercury in U.S. Coal – Abundance, Distribution, and Modes of Occurrence," USGS Fact Sheet FS-095-01, September 2001; available at pubs.usgs.gov/fs/fs095-01/fs095-01.pdf). The upper 95 percent confidence level mercury content value from these coal analyses is 0.13 ppmw. The corresponding uncontrolled mercury emission rate, assuming all of the mercury in the coal is released to the atmosphere, would be 10.0 lb/TBtu or 230 lb/yr.

A. Identification of Available Mercury Control Strategies/Technologies

The following paragraphs describe alternative technologies that are being evaluated for feasibility and effectiveness of controlling mercury emissions from electric utility boilers as presented in the 2005 EPA technology review report. The technologies are grouped into the following categories:

i. Native Controls:

a. Particulate Controls
b. SO_2 Controls
c. NO_x Controls
d. SDA/FFB Controls

ii. Enhanced Controls

a. Fuel Blending
b. Oxidizing Chemicals
c. UBC Enhancement
d. Mercury Specific Catalyst
e. Improvement of Wet FGD Mercury Capture

iii. Sorbent Injection: Add-on mercury control equipment; and

iv. Additional Alternatives

The following text provides a brief overview of the above-cited control options/technologies/strategies that have been evaluated for the proposed project.

i. Native Controls

Native controls include mercury removal accomplished by existing controls for NO_x, SO_2, and particulate.

a. Particulate Controls

Survey and test data indicate that ESPs provide limited mercury emissions control. Because the control they do provide results from the capture of particulate-bound mercury, its effectiveness depends on the relative amount of particulate mercury speciation. FFBs have been demonstrated to be relatively more effective at controlling mercury emissions from bituminous and low rank coals. This appears to be due to the effect of the ash-cake that collects on the surface of the filters. The cake enhances gas-particle interactions, promoting adsorption of oxidized mercury and, where there is adequate chlorine, oxidation of elemental mercury.

b. SO_2 Controls

Wet FGD scrubbers have demonstrated mercury removal efficiencies ranging from less than 50% to approximately 75% for bituminous coal. No data were found that evaluated effectiveness when burning low rank coal. Because oxidized mercury – which is generally present in high proportion for bituminous coal – is water soluble, wet FGD removal effectiveness would be expected to be higher than has been observed. It is thought that wet FGD systems tend to promote chemical reduction of oxidized mercury to elemental mercury, resulting in subsequent re-emission.

While evaluations of mercury emissions from CFB Boilers do not appear in the literature, one of the primary advantages of CFB Boiler technology is the reduction of SO_2 emissions, which in turn may benefit mercury capture in the exhaust gas stream. Potential for mercury capture co-benefits associated with CFB technology will be addressed in a subsequent portion of this analysis.

c. NO_x Controls

SCR units appear to enhance oxidation of elemental mercury when burning bituminous coal, but limited data indicate marginal effectiveness when burning subbituminous coal.

d. SDA/FFB Systems

Emissions control systems consisting of spray dryer absorbers (SDAs) and FFBs have been demonstrated to provide over 90 percent mercury control efficiency for bituminous coal combustion. Average control efficiency when burning subbituminous coal is approximately 25 percent. This low effectiveness – less than has been observed with FFBs alone – is thought to be the result of HCl removal by the SDA. It is thought that bituminous coal contains enough excess chlorine that HCl scrubbing by the SDA is not a limiting factor for that coal rank.

ii. Enhanced Controls

Enhanced controls include mercury control strategies accomplished through the enhancement of existing controls.

a. Fuel Blending

Replacing a portion of PRB subbituminous coal with bituminous coal has been evaluated with mixed results ("Evaluation of Sorbent Injection for Mercury Control," Quarterly Technical Report, Reporting Period:April 1, 2005 – June 30, 2005; Sharon Sjostrom; available at www.netl.doe.gov/coal/E&WR /mercury/control-tech/sorbent-injection2.html.). In one short-term test, mercury capture increased from approximately 25 percent to nearly 80 percent. At another facility, no additional mercury capture was observed.

b. Oxidizing Chemicals

Limited short-term testing has been conducted on the effects of introducing chlorine and other halogens into the combustion system. The test results vary depending on boiler type, coal quality, and downstream pollution control equipment. Test results show some promise for adding these chemicals with ACI to achieve high levels of mercury emission reduction. However, further evaluation of impacts to operations has been recommended in addition to further evaluation of effectiveness over various conditions and durations.

c. UBC Enhancement

Derivative data from field tests have provided evidence that increasing the portion of unburned carbon (UBC) in coal ash enhances mercury capture. Adjusting combustion conditions to increase ash UBC levels will require evaluation on a case-by-case basis of detrimental effects to boiler operation and efficiency.

d. Mercury-Specific Catalysts

Testing is ongoing regarding the effectiveness and feasibility of injecting oxidizing chemicals or employing catalyst systems designed to facilitate oxidation of elemental mercury.

e. Improvement of Wet FGD Mercury Capture

Limited testing has been conducted on the potential for SCR and an injected chemical additive to improve elemental mercury oxidation and to limit or eliminate chemical reduction of oxidized mercury in a wet FGD system. Results from the tests, which so far have been carried out only on bituminous coal, indicate that SCR and/or chemical additives can improve overall mercury capture in a wet FGD/ESP system firing bituminous coal.

iii. Sorbent Injection

Injection of various sorbents into the boiler exhaust stream has been the primary technology under evaluation that is specific to mercury control (i.e., it does not rely on a co-benefit of controlling some other pollutant). This technology was identified as having potential to reduce mercury emissions from coal-fired electric utility boilers because of its successful history of application to waste incinerators for the same purpose. Sorbent injection technology used in waste incinerators is not directly transferable to electric utility boilers, however, due to significant differences in operational requirements and in exhaust gas characteristics such as mercury concentrations, chemical makeup, and volume.

As suggested by the name, sorbent injection technology works by providing active surfaces that promote adsorption of exhaust mercury. The result is particulate-bound mercury that can be captured by particulate emissions control equipment such as an ESP or FFB. Standard ACI has proven to be effective for improving mercury emissions from bituminous coal on a relatively consistent basis. Its effectiveness on subbituminous coal emissions is dependent upon facility and operating parameters, and has been consistently lower than that observed with bituminous coal. Recent research suggests that the levels of chlorine and sulfur in the combustion gases are key in determining mercury capture efficiency.

Several alternative injection media have been and continue to be evaluated to address deficiencies and concerns associated with ACI. One class of alternative media consists of standard ACI that has been treated with a halogen, most commonly boron. The treatment serves to enhance elemental mercury oxidation and overall mercury adsorption. Initial results from several short-term tests indicate that halogenated ACI could potentially be more effective at mercury removal than standard ACI over a range of parameters while offering other benefits. Several evaluations of this technology are ongoing, and additional tests are planned.

Other specialty sorbent materials have been identified and are being evaluated for specific applications. These materials are being developed and evaluated primarily for the purposes of reducing control costs and improving potential for beneficial use of the collected ash.

iv. Additional Alternatives

An additional mercury control alternative, one that was not discussed in the EPA technology review report, is to treat the coal in order to remove a portion of its mercury prior to combustion. A joint venture company, the Alaska Cowboy Coal Power Consortium, has demonstrated in small-scale tests that their process for drying low rank coals can also remove a portion of the coal's mercury content. It has yet to be demonstrated on a full scale.

B. Technical Feasibility Analysis

The NSR Manual describes two key criteria for determining whether an alternative control technology is technically feasible. According to the NSR Manual, a technology must be "available" and "applicable" in order to be considered technically feasible. A technology is available "if it has reached the licensing and commercial sales stage of development." An identified alternative control technique may be considered presumptively applicable if "it has been or is soon to be deployed (e.g., is specified in a permit) on the same or similar source type." The following paragraphs evaluate the technical feasibility of the alternative control technologies identified above by applying these criteria of availability and applicability.

i. Native Controls

Insofar as technologies applied to control emissions of other pollutants also provide mercury control co-benefits, these technologies are considered technically feasible.

ii. Enhancement of Existing Controls

None of the native control enhancement technologies described above have demonstrated widespread applicability to coal-fired utility boilers on a full-scale basis. Further, and more importantly, none have been evaluated on any level for applicability to CFB Boiler technology. For these reasons, identified native control enhancement technologies are considered to be technically infeasible for application to the SME-HGS. The Department has recently determined that mercury capture enhancement technologies are generally not technically feasible. In the analysis of a recent permit for a PC electrical utility boiler the Department stated: "The Department determined that enhanced FGD is not currently an available control strategy and thus is not a suitable candidate for a full-scale mercury BACT control system at this time" (Montana Air Quality Permit #3185-02, Final: 05/16/05; page 29).

iii. Sorbent Injection

While sorbent injection technology has been tested under a variety of conditions, it is still being evaluated as an applicable control technology for mercury emissions. Its applicability has not been demonstrated on a full-scale CFB Boiler. Based on two recently permitted coal-fired electrical generating units in Montana accepting conditions requiring ACI installation for mercury control and the availability of vendor guarantees on ACI, the Department determined that sorbent injection is available. The following citations provide further information regarding this determination. Also, under the current BACT analysis, SME-HGS proposed, and the Department required, mercury control equipment (IECS) that is equivalent to ACI/sorbent injection.

- The DOE Office of Fossil Energy has recently published a circular that describes ACI as the most promising near-term mercury control technology, but it qualifies that observation by stating that "the process applied to coal-fired boilers is still in its early stages and its effectiveness under varied conditions…is still being investigated." It further states, "technology to cost-effectively reduce mercury emissions from coal fired power plants is not yet commercially available" ("Mercury Emissions Control R&D," updated June 21, 2005; available at http://www.fossil.energy.gov/programs/powersystems/pollutioncontrols/overview_mercurycontrols.html).
- As noted above, the EPA technology review document concludes, "It is believed that ACI and enhanced multipollutant controls will be available after 2010 for commercial application on most, if not all, key combinations of coal type and control technology to provide mercury removal levels between 60 and 90%. Also optimized multi-pollutant controls may be available in the 2010-2015 timeframe for commercial application on most, if not all, key combinations of coal type and control technology to provide mercury removal levels between 90 and 95%" ("Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update," Air Pollution Prevention and Control Division, National Risk Management Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency; February 18, 2005).

iv. Additional Alternatives

Coal drying, with the co-benefit of mercury removal, has not been proven on a large scale and is not commercially available. It is therefore not technically feasible.

C. Ranking of Available and Technically Feasible Mercury Control Options by Efficiency

The only remaining alternative mercury control technologies are those that provide mercury control co-benefits while reducing emissions of other pollutants. As noted above, the native controls that have been evaluated for mercury control effectiveness are wet and dry (or semi-dry) FGD scrubbers for SO_2 control; ESPs and FFBs for particulate control; and, to a lesser extent, SCR for NO_x control. These systems, individually and in combination, have demonstrated wide variability with respect to mercury reduction efficiency – anywhere from zero to over 90 percent. Effectiveness depends largely on coal quality (especially chlorine content), but also on a host of other design and operational parameters.

SME-HGS is proposing to control NO_x emissions with an SNCR system, SO_2 emissions by CFB technology that employs limestone and hydrated ash reinjection, and particulate emissions with an FFB. The combined air pollution control system is referred to as an integrated emissions control system (IECS). As part of evaluating the performance of CFB in combusting PRB coal, SME-HGS conducted a pilot-scale test burn in February 2005. The test burn was conducted in an ALSTOM Power test facility using 80 tons of Montana PRB coal and 20 tons of Montana limestone (80 tons of coal would be combusted in approximately 30 minutes in the SME-HGS main boiler when firing at full capacity). A summary of the test results is included in Section 3.12 of the application for this air quality permit and a complete copy of the test burn report is in Appendix I of the application for this air quality permit.

The pilot test results indicate a potential for approximately 88% (0.7 lb/TBtu) mercury removal in a CFB combustor with HAR and fabric filter controls. This level of mercury control is much greater than most utility boilers burning subbituminous coal and utilizing native control systems. It is also near the high end of values observed in the many test programs that have been and are being conducted on subbituminous coal combustion in utility boilers. However, the test burn alone does not provide sufficient data to allow boiler manufacturers to confidently extrapolate the data and guarantee mercury emissions control in a full-scale CFB unit with IECS.

The Department has recently become aware of emissions testing at East Kentucky Power Cooperative Gilbert Unit 3 during the summer of 2005. This testing program included measurements of mercury emissions on a CFB Boiler equipped with an HAR, SNCR and FFB. Short-term testing results showed stack mercury emissions of 1.0 lbs/Trillion Btu (TBtu) and 89.5% control of the input mercury from coal. While these test results are very promising, Gilbert Unit 3 burns eastern bituminous coal with a relatively high chlorine content (0.031% during test period) from many different sources in Kentucky and Illinois. For comparison, Spring Creek coal has a chlorine content of <0.01%. Recent research conducted by ADA-ES, with support from DOE/NETL, EPRI and industry partners, confirms that available chlorine is a key factor in oxidizing elemental mercury in the combustion gases and in controlling mercury emissions from PRB coal ("Full-Scale Evaluations of Mercury Control for Units Firing Powder River Basin Coals" Sjostrom, Sharon, *et al.*, ADA-ES, O'Palko, Andrew, USDOE/NETL, Chang, Ramsay, EPRI. DATE not given).

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

For a discussion of collateral economic, energy, and environmental impacts associated with the proposed CFB Boiler and associated controls, refer to previous sections of this BACT analysis.

E. Mercury BACT Determination

SME-HGS proposed a mercury emissions floor and to conduct continuous mercury-specific monitoring of the CFB Boiler technology including limestone injection, SNCR, HAR, and FFB control, collectively termed the integrated emission control system (IECS), as mercury BACT for the proposed project. Further, as necessary, SME-HGS proposed the installation and operation of additional mercury emissions control technologies to establish scientifically justifiable and site-specific mercury emissions reductions above and beyond the permitted and BACT determined mercury floor emissions levels. The SME-HGS proposed mercury emissions floor was a maximum mercury emission rate expressed as either:

- 80% mercury reduction, based on a 12-month rolling average, or
- 2.0 lb mercury/TBtu, based on a 12-month rolling average.

Based on Department verified information contained in the SME-HGS application for this air quality permit, including mercury specific source testing results obtained through the simulated and comprehensive combustion, performance, and emission testing program conducted prior to application, and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed mercury emission control strategy and mercury floor emission limit(s) do not constitute BACT in this case. Considering the above-cited information as well as a recent mercury specific BACT determination for a similar source permitted for operation in Montana, the Department determined that the appropriate mercury BACT emissions limit(s) for the proposed project incorporating the IECS is either:

- 90% mercury reduction, based on a 12-month rolling average, or
- 1.5 lb mercury/TBtu, based on a 12-month rolling average.

The two-part limit accounts for two complementary operational factors. First, coal quality is not constant, even within a given coal deposit. At the extremely low values under consideration, a small proportional change in coal mercury content can have a significant impact in compliance potential. Second, control efficiencies generally decrease as inlet concentrations decrease, particularly as inlet concentrations become very low, as in the case of mercury concentrations in utility boiler exhaust. If SME-HGS should receive coal with higher than normal mercury content, it may be difficult to comply with the lb/TBtu limit, but compliance with the percent reduction requirement would be achievable. Conversely, if a particular coal supply contains less mercury than normal, the percent reduction requirement may be less readily attainable while the emission rate may be more so.

To confirm the performance of the CFB Boiler and IECS in reducing mercury emissions, SME-HGS will be required to monitor and analyze mercury control performance data after commencement of commercial operations and to report this information to the Department. The results of the final analysis will then be used to confirm compliance with the BACT-determined mercury emissions limit(s).

If the CFB Boiler operating with the IECS is unable to demonstrate compliance with the mercury limits established through the BACT determination, SME-HGS is required to achieve the BACT-determined mercury reductions/limits through the installation and operation of mercury-specific emission controls. Within 18 months after commencement of commercial operations, SME-HGS shall install and operate an activated carbon injection control system or, at SME-HGS's request and as approved by the Department, an equivalent technology (equivalent in removal efficiency) to comply with the applicable mercury BACT emission limits.

8. Radionuclide Emissions

Most natural materials, including coal, contain trace quantities of radioactive components. When coal is combusted, radionuclides are contained in the combustion gases. Radionuclides from a CFB Boiler are emitted primarily as particulate matter. Pollution control equipment that is used to remove PM as described in the CFB Boiler filterable PM BACT determination will also effectively remove radionuclides. The Department determined that radionuclides can be controlled by more than 95% with traditional PM/PM_{10} control equipment (e.g., FFB or ESP).

A. Identification of Available Radionuclide Control Strategies/Technologies

The two most effective and available control options for radionuclides are an FFB and ESP as described in the CFB Boiler BACT determination for filterable PM emissions. Other less effective control options are also listed in the CFB Boiler BACT determination for filterable PM.

B. Technical Feasibility Analysis

FFB and ESP are technically feasible.

C. Ranking of Available and Technically Feasible NO_x Control Options by Efficiency

FFB and ESP control options have the capability of controlling radionuclides by more than 95%, although FFBs are slightly more effective, particularly for smaller particulate matter.

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

Both FFB and ESP would produce a solid waste stream, with a wet ESP creating a wet solid waste stream. No significant environmental, economic, or energy impacts are identified as being associated with the use of an FFB or ESP, although an ESP would require more energy than a FFB. In addition, when an FFB is downstream of a dry FGD unit, additional SO_2 is removed, along with acid gases and H_2SO_4 mist that have formed in the exhaust stream, thereby, providing additional co-benefit pollution control.

E. Radionuclide BACT Determination

SME-HGS proposed the use of an FFB as BACT for radionuclide emissions. Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the FFB emission control strategy constitutes BACT for radionuclides in this case.

Because an FFB will achieve slightly better control than an ESP and FFB control is deemed BACT for filterable PM. The Department determined that the filterable PM BACT emission limit will act as a surrogate BACT emission limit for radionuclides. The BACT determination for radionuclides is consistent with previous Department BACT determinations for radionuclides. Further, the Department determined that the periodic source testing (filterable PM) and applicable recordkeeping and reporting requirements contained in the permit will adequately monitor compliance with the permitted BACT requirements.

B. Coal, Limestone, and Ash (Fly and Bed Ash) Material Handling and Storage Operations BACT Analysis and Determination

The following BACT determination was conducted for PM/PM_{10} emissions resulting from both the handling and storage of coal, used as primary CFB Boiler fuel; limestone, used for CFB injection technology and SO_2 control; and ash (fly and bed-ash) produced by coal combustion in the CFB Boiler. The BACT analysis is broken down in to two parts including material handling operations and material storage operations.

1. Material Handling PM/PM_{10} Emissions

Material handling at the SME-HGS facility includes the transfer and conveying of coal, limestone, and ash. PM/PM_{10} emissions will be emitted from the conveying, handling, and transferring of these materials. The application for this permit lists all of the conveyors and material handling transfer points located throughout the SME-HGS facility.

Typically, limestone and coal are moved within a facility using belt conveyors and bucket elevators. Ash is typically moved via pneumatic conveyors. Both methodologies have the potential to create particulate emissions.

As the flow of material passes through the transfer or drop point to a conveyor, particulate emissions are generated. The quantity of particulate emissions generated by a transfer point varies with the volume of material passing through the point, the particle size distribution of the material, the moisture content of the material, and the exposure to prevailing winds at the transfer point. EPA's AP-42, Section 13.2.4 describes a methodology and provides equations to calculate uncontrolled particulate emissions from both batch and continuous process transfers, or drop point transfers, with an emission factor rating of A, giving the equation the highest level of confidence.

A. Identification of Available PM/PM_{10} Control Strategies/Technologies

Methods of controlling particulate emissions from conveyors and transfer points have been developed, which can significantly reduce emissions rates. These methods are based on several principles: reducing the amount or flowrate of material passing through the transfer point, passing larger sized material and minimizing the small particle size content of the material, increasing the moisture content of the material to increase agglomeration of fine material, and shielding or enclosing the transfer point to protect the transfer point from wind. Enclosures often include fan-powered FFB to collect any airborne particulate at a common point for re-use or disposal.

As previously stated, there are a number of available control technologies that can theoretically be employed to control PM/PM_{10} emissions from materials handling sources. The following table summarizes available controls for PM/PM_{10} emissions from conveyors and transfer points.

Technology	Description
Wet Dust Suppression / Wetted Material	A water spray or fogger adds water to the material being handled with or without surfactant. Emissions are prevented through agglomerate formation by combining small dust particles with larger particles or with liquid droplets. Water retained by the material prevents emissions from storage systems and downstream transfers.
Enclosure (including partial enclosure)	Structures or underground placement can be used to shelter conveyors and material transfer points from wind to prevent particulate entrainment. Enclosures can either fully or partially enclose the source.
Enclosure with ESP	Conveyors can be enclosed and have emissions-laden air collected from the enclosure and ducted to an ESP. An ESP uses electrical forces to move entrained particles in the air onto a collection surface. A cake of particulate forms on the collection surface, which is periodically “rapped” by a variety of means to dislocate the particulate, which drops down into a hopper for collection and disposal or reuse.
Enclosure with FFB	Conveyors are often enclosed and emissions-laden air is collected and ducted to the FFB. Pneumatic conveyors are typically sealed with the exception of a FFB or bin vent on the air discharge. In either case, the air-flow passes through tightly woven or felted fabric, causing particulates in the flow to be collected on the fabric by sieving and other mechanisms. As particulate collects on the filter, collection efficiency increases. However, as the dust cake thickness increases so does the pressure drop across the bags. Bags are intermittently cleaned by mechanisms such as shaking the bag, pulsing air through the bag, or temporarily reversing the airflow direction. Material cleaned from the bags is collected in a hopper at the bottom of the FFB.

B. Technical Feasibility Analysis

The technologies listed in the above table are considered technically feasible, with the following exceptions. Since the proposed emergency coal storage pile is not enclosed, having an enclosed transfer point to the pile is considered technically infeasible. As a result, adding FFB or ESP to the enclosure is also considered technically infeasible; therefore, these strategies are removed from further consideration for that transfer point.

Ash handling from temporary storage (e.g., silo) to permanent storage (e.g., monofill) by enclosure with ESP or FFB control is not an industry accepted practice. Fly ash consists primarily of fine particles, which easily become airborne, and bed ash has a significant portion of fine particles. These materials are not suitable for collection with these listed technologies, as the baghouse or ESP will pick up a significant portion of the material stream and quickly become overloaded. Therefore, these strategies are removed from further consideration for ash handling.

C. Ranking of Available and Technically Feasible PM/PM_{10} Control Options by Efficiency

The following table summarizes the available control options, their respective potential control efficiency values, and their ranking for the purposes of this BACT analysis.

Technology	**Estimated Control Efficiency**	**Rank**
Enclosure with FFB	99.5%	1
Enclosure with ESP	Up to 99%	2
Enclosure	Varies with Degree of Enclosure 3-Sided Enclosure = 50% Complete Enclosure = 90%	3
Wet Dust Suppression (including water spray with or without surfactant and wet material	50%	4
No Add-On Control	---	5

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following text provides a brief discussion of the available control options and an analysis of BACT applicability in this case.

i. Enclosure with FFB

For most of the proposed sources, an enclosure with FFB dust collector control has been deemed technically feasible. FFB operations and maintenance are relatively simple. FFB are generally considered an industry standard for material transfer point particulate control and are deemed economically feasible in this case. Because FFB provides the highest level of control, no further evaluations are necessary for sources with proposed with FFB control.

ii. Enclosure with ESP

Because ESPs can theoretically attain up to 99% control efficiency, ESP control was evaluated. The ESP could only be used to control the limestone and ash particulate emissions and not for coal handling because of the high explosion potential of coal dust collection in an ESP. ESPs are not typically used for control of limestone or ash handling emissions due to the high initial costs of installation, complexity, and technical difficulty of operations. Costs associated with the technical obstacles have not been quantified in this analysis. Industry norms indicate, however, that use of ESPs for particulate control from material handling transfer points is unduly complex and cost prohibitive. Therefore, the use of enclosures with an ESP is eliminated from further consideration in this BACT analysis.

iii. Enclosures

Using enclosure structures or underground placement to shelter material from wind entrainment is often an economic means to control PM/PM_{10} emissions. Enclosures can either fully or partially enclose the source and control efficiency is dependent on the level of enclosure. Enclosures are considered for the coal pile reclaim hopper, belt feeder and transfer to Conveyor CC03. All of this equipment is located underground, and covered by the coal pile. The emergency storage pile has no regularly scheduled use. Only a very small fraction of the total coal consumed at the SME-HGS facility is anticipated to go through the storage pile. As such, SME-HGS believes the cost of providing additional control by the installation of an enclosure is difficult to quantify and would result in relatively large cost/ton effectiveness figures. Complete enclosure provides the highest level of control of the remaining alternatives.

iv. Wet Dust Suppression

Wet dust suppression works by causing fine particles to agglomerate through the introduction of moisture into the material stream. The agglomerated particles resist entrainment by wind. Because use of wet dust suppression techniques, including fogging water spray with or without surfactant, can achieve control efficiency of 50% or greater, wet dust suppression was evaluated.

Wet dust suppression is not always a practical control alternative. Occasionally, moisture may interfere with further processing such as screening or grinding where agglomeration is counterproductive. In addition, application of additional moisture in fuel handling operations can increase fuel costs and/or cause upset combustion conditions. In some cases, water may not be readily available and piping water to the site may be cost-prohibitive. Finally, using water sprays when the temperatures are below freezing causes operational difficulties.

When using wet dust suppression, the decision to use or not to use surfactants is often somewhat discretionary and based on availability of a water source. Addition of surfactants to the water lowers its surface tension and improves wetting efficiency. As a result, less water is used and application is required less frequently. Wet dust suppression is particularly applicable to ash handling activities. Ash is often mixed with small quantities of water in a pug mill before disposal.

E. Material Handling PM/PM_{10} Emissions BACT Determination

In summary, SME-HGS proposed the use of the highest level of control that is technically and practically feasible for the affected material handling PM/PM_{10} emission sources.

Proposed BACT for coal, limestone, and ash handling conveyors will be partial or full enclosures. Coal/limestone belt conveyors will be partially enclosed with a cover that extends past the conveyor belt, or is fully contained within a building. The limestone bucket elevator conveyors will be fully enclosed, and the ash handling pneumatic conveyors will be fully enclosed and sealed.

SME-HGS proposes to use enclosures with FFB or bin vent control as BACT for PM/PM_{10} on almost all of the material transfer emission points. Enclosure with a baghouse or bin vent provides the most effective control and is considered the industry norm for control of materials handling transfer points. Based on Department verified information contained in the application for this permit, the following exceptions to the material transfer point BACT determination of FFB or bin vent control apply in this case: Complete enclosure is BACT for PM/PM_{10} on the transfer points at the emergency coal pile to reclaim hoppers, reclaim hopper to belt feeder, and belt feeder to Conveyor CC03 because FFB or ESP control would not be cost-effective due to the relatively low potential to emit of the sources since the transfer points are located beneath (i.e., underground) the emergency coal pile. Further, enclosures for these sources is the most cost effective control given the infrequent operation of the equipment.

Further, the Department determined that wet dust suppression constitutes BACT for PM/PM_{10} emissions from the fly ash and bed ash conveyor and transfer emission points (removal from the silo). The FFB, ESP, and enclosure control options are technically infeasible. Wet dust suppression is proposed for ash handling after the pug mill for removal from the plant collection system. Wet dust suppression and partial enclosure (i.e., lowering well) are also proposed for the transfer of coal to the emergency coal storage pile because the FFB and ESP control options are practically infeasible for a single transfer point that will operate intermittently.

A review of the EPA's RBLC database shows that the proposed BACT presented in the sections above conforms to similar sources recently permitted under the PSD program. The data from the RBLC website is summarized in the application.

The Department determined that the affected material handling and transfer points operating under the proposed control requirements and the established FFB and bin vent emission limit(s) of 0.005 gr/dscf and 0.01 gr/dscf, respectively, constitute BACT in this case. Further, the Department determined that the periodic PM/PM_{10} source testing and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted material transfer BACT requirements.

2. Material Storage PM/PM_{10} Emissions

Materials stored at the SME-HGS facility include coal, limestone, fly ash and bed ash. particulate emissions will be emitted from the storage of these materials. Storage of these materials in large quantities, as required by a coal-fired power plant of this size, has historically been accomplished with piles. More recently, control technologies have been applied to the storage of these materials.

Sections 13.2.4 and 13.2.5 of AP-42 describe the process by which storage piles generate fugitive particulate emissions. The quantity of particulate emissions generated by a storage pile varies with several factors, including wind speed acting upon the surface of the pile, threshold friction velocity of the pile, frequency of disturbance of the pile, and area of disturbance of the pile. Threshold friction velocity takes into account materials makeup of the pile, material size distribution and moisture content of the material in the pile. Emissions are only generated when the wind speed acting upon the pile exceeds the friction threshold velocity.

A storage pile of aggregate material, such as coal, limestone or ash, is typically composed of pieces of material of different sizes, including non-erodible elements of the material (greater than 1 cm in diameter) mixed with smaller, erodible material sizes, including silt. The pile surface has a finite availability of the erodible portion of material, which tends to be removed from the pile rapidly during a wind event. This is referred to as erosion potential of the pile. Since undisturbed piles quickly lose their erosion potential during a wind gust, emissions are significantly reduced until the pile is disturbed, when the erosion potential is restored. If a crust is formed on the pile due to erosion, precipitation, water spray or surfactant application, the emission potential is significantly reduced because of the resulting increase of the threshold friction velocity of the pile.

Methods of controlling particulate emissions from the storage of materials have been developed which can significantly reduce fugitive emissions from storage of materials. These methods are similar to the transfer point emissions reduction methods, and are based on several principles:

- Minimizing material transfers to and from the pile (pile disturbances),
- Storing larger sized material and minimizing the small particle size content of the material,
- Increasing the moisture content of the material to increase agglomeration and cementation of fine material to larger particles, and
- Shielding or enclosing the materials to protect from wind erosion

Enclosures may include fan-powered fabric filter baghouses or un-powered bin vent filters to collect airborne particulate.

A. Identification of Available PM/PM_{10} Control Strategies/Technologies

A number of available control technologies can theoretically be employed to control PM/PM_{10} emissions from materials storage. The following table summarizes available controls for PM/PM_{10} emissions.

Technology	Description
Inactive Storage Pile with No Additional Control	An inactive storage pile minimizes or eliminates disturbances which reduces the erosion potential of the pile. It also allows a crust to form on the pile over time, which helps resist erosion by increasing the pile's threshold friction velocity.
Inactive Storage Pile with Wind Fence	An inactive pile with a wind barrier or wind fence builds upon the control listed above by reducing the wind speed that acts upon the pile surface. This minimizes the number of times that the wind velocity exceeds the threshold friction velocity, thereby reducing the number of emission events or the duration of emission events.
Inactive Storage Pile with a Permanent Wet Suppression System and Wind Fence	An inactive pile with compaction and wet suppression builds upon the control listed for an inactive storage pile alone. Compaction and wet suppression actively promote the formation of a crust on the pile by increasing the amount of agglomeration or cementing of the surface materials. This significantly increases the threshold friction velocity of the surface and reduces erosion potential. This strategy works especially well with materials that bond together with water application, such as ash. Wind fences may or may not be applied with this option depending on the additional control a wind fence may add to the overall control of this option.

Enclosure	Using structures or underground placement to shelter material from windentrainment. Enclosures can either fully or partially enclose the source.
Enclosure with FFB or Bin Vent	Emissions-laden air is collected from the enclosure and ducted to the FFB or bin vent. The flow passes through tightly woven or felted fabric, causing particulates in the flow to be collected on the fabric by sieving and other mechanisms. As particulate collects on the filter, collection efficiency increases. However, as the dust cake thickness increases so does the pressure drop across the bag.

B. Technical Feasibility Analysis

All of the potentially applicable control technologies listed above are considered technically feasible for the storage of coal, limestone, and ash.

C. Ranking of Available and Technically Feasible PM/PM_{10} Control Options by Efficiency

The following table summarizes the available options, their respective potential effectiveness values, and their ranking for this BACT analysis.

Technology	Estimated Control Efficiency	Rank
Enclosure with FFB or bin vent	99.5%	1
Inactive Storage Pile with Permanent Wet Suppression System and Wind Fence	95%	2
Inactive Storage Pile with Wind Fence	Varies with Degree of Enclosure 3-Sided Enclosure = 50% Complete Enclosure = 90%	3
Enclosure	50%	4
Inactive Storage Pile with Best Management Practices	25-90%	5
Active Storage Pile with No Add-On Control	---	6

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following text provides a brief discussion of the available control options and an analysis of BACT applicability in this case.

i. Enclosure with FFB or Bin Vent

If a storage system is completely enclosed, a FFB or bin vent can usually be added to the enclosure to more efficiently control particulate emissions. FFBs or bin vents on enclosures are generally considered an industry standard for particulate control on enclosed, active aggregate storage systems. Enclosures (silos) with bin vent control are proposed for short-term coal storage, limestone storage and short-term ash storage. SME-HGS proposes to use enclosure and FFB or bin vent control for all active coal, limestone, and ash storage.

ii. Enclosures

Using enclosure structures to shelter material from wind entrainment is often used to limit control particulate emissions from stored aggregate materials. Enclosures can either fully or partially enclose the source and control efficiency is dependent on the level of enclosure. Enclosures for aggregate materials often come in the form of walls around a pile, storage buildings or silos. Enclosures are generally not sealed and have emissions associated with adding and removing materials. Active storage piles are often enclosed. Inactive storage piles are generally not enclosed.

iii. Inactive Storage Pile with Permanent Wet Suppression System and Wind Fence

Applying wet dust suppression to an inactive pile contributes greatly to crust formation, which maximizes particle agglomeration on the pile surface. The agglomerated particles resist entrainment by wind on the pile surface, and minimize particulate emissions. Wet dust suppression is not without its drawbacks. Occasionally, moisture may interfere with further processing such as screening or grinding where agglomeration is counterproductive. In addition, application of additional moisture in fuel handling operations can increase fuel costs and/or cause upset combustion conditions. Using water sprays when the temperatures are below freezing causes operational difficulties. Piles are usually not watered when the ambient temperature is below freezing.

When using wet dust suppression, the decision to use or not to use surfactants is often somewhat discretionary and based on availability of a water source. Addition of surfactants to the water lowers its surface tension and improves wetting efficiency. As a result, less water is used and application is required less frequently. In the case of the coal pile, application of surfactants may be required to achieve 90% control efficiency.

iv. Inactive Storage Pile with Wind Fence

An inactive storage pile can be protected from prevailing winds with a wind barrier or wind fence. A properly designed wind barrier can effectively reduce wind speeds at the pile surface by 20 – 60%. The wind barrier should be as high as the pile, and at least as wide as the pile to achieve maximum effectiveness. Reducing wind speed acting on the pile surface reduces particle entrainment and thereby reduces particulate emissions from the stored material.

v. Inactive Pile with Best Management Practices

Using an inactive storage pile with best management practices generally includes initial compaction of material by bulldozer or other tracked heavy equipment, minimizing the number of pile disturbances, minimizing the frequency of pile disturbances, minimizing the surface area of the pile, and applying wet dust suppression to disturbed areas of the pile to help re-form a crust as necessary to reduce fugitive emissions.

vi. Active with No Additional Control

SME-HGS believes that it is not modern, standard industry practice to store coal or ash in an active pile without further emissions controls. Recent BACT determinations show that additional control on active or inactive piles is warranted.

SME-HGS proposes to use enclosure and baghouse or bin vent control for all active coal, limestone and ash storage. Since this option has the highest degree of particulate control, no economic analysis of this option has been performed for active storage. Economic impacts associated with the PM/PM_{10} control options for inactive storage piles of coal and ash listed above were compared using estimated annualized capital, operating, and maintenance costs. Cost estimates were supplied by SME-HGS and its engineering contractors. If data was not available from SME-HGS, best engineering judgment was used. Detailed information regarding economic impacts is contained in the application for this air quality permit.

E. Material Storage PM/PM_{10} Emissions BACT Determination

SME-HGS proposes to use a combination of enclosures (silos) with bin vent control for active storage of coal, limestone, and ash, and best management practices for the emergency coal storage and ash storage. Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed PM/PM_{10} emission control strategies and applicable emission limits constitute BACT in this case. The following table lists the proposed BACT control requirements and emissions limits, as applicable.

Material Stored	**Method**	**Applicable Limit**
Active Coal Storage	Coal Silo and Coal Bunkers with FFB Control	0.005 gr/dscf
Inactive Coal Storage – Emergency Coal Storage Pile	Inactive Storage Pile with Best Management Practices	NA
Limestone Storage	Limestone Silo and Limestone Bunkers with FFB Control	0.005 gr/dscf
Short-Term Ash Storage	Fly-Ash Silo and Bed-Ash with bin vent Control	0.01 gr/dscf
Long-Term Ash Storage	Inactive Storage Pile with Best Management Practices until Monofill is Capped	NA

Based on Department verified information contained in the application and taking into consideration technical, environmental, and economic factors, the Department determined that enclosure in silos with FFB or bin vent control for active coal, limestone, and short-term ash storage constitutes BACT in this case. Enclosure with FFB or bin vent control provides the highest level of particulate control, with reasonable costs and minimal adverse environmental impacts. Normal material flow consists of loading the coal and limestone bunkers on a daily basis from the enclosed coal and limestone silos, through the tripper conveyor system. The bunkers will be enclosed and controlled by baghouse DC4. The coal silo will be enclosed and controlled by baghouse DC2. The limestone silo will be enclosed and controlled by baghouse DC5. After the fly ash is removed from the FFB associated with the boiler exhaust gas stream, the ash will be temporarily stored in ash silo AS1, which is enclosed and controlled by a bin vent filter, DC6. Bed ash removed from the boiler will be temporarily stored in the bed ash silo AS2, which is enclosed and controlled by bin vent DC7.

Based on Department verified information contained in the application and taking into consideration technical, environmental, and economic factors, the Department determined that an inactive storage pile, with best management practices, including compaction and wet dust suppression as necessary (i.e., water truck application) constitutes BACT for emergency reserve storage of coal and long-term storage of ash prior to capping of the open on-site ash storage cell. SME-HGS will be submitting, separate from the air quality permit application, a solid waste management plan for the long-term storage of the ash in the monofill. Based on the emission inventory prepared for the SME-HGS facility, the inactive emergency coal storage pile is estimated to emit 1.63 tons per year of PM_{10} (based on conservative emission calculations). Recent PSD permitting actions show this storage method constitutes BACT. The Department determined that the addition of a wind fence or permanent wet suppression system to the inactive coal pile yields a minimal additional control of particulate emissions once the coal pile is compacted and becomes encrusted. The cost analysis supplied in the application for this air quality permit shows that the control options with higher particulate control have extremely high costs on a dollar per ton of PM_{10} removed basis. Detailed information regarding the cost analysis is contained in the application for this permit action. The Department determined that these costs are excessive and far above industry norms for PM_{10} control. Therefore, all additional control options above best management practices for inactive coal storage have been eliminated from further consideration under this BACT analysis.

Based on Department verified information contained in the application, the Department determined that an inactive storage pile, with best management practices, including compaction and wet dust suppression as necessary (i.e., water truck application), constitutes BACT for storage of ash prior to capping of the open monofill cell. SME-HGS proposes to mix fly ash and bed ash with small quantities of water in the pug mill after removal from the ash silos. The ash-water mixture is hauled to the ash monofill, where it is pushed into location and compacted. Ash, when mixed with small quantities of water, forms a cement-like material that has very low wind erosion potential. The monofill is composed of cells, formed by excavating earthen material from the cell location and using that material to form a berm around the monofill cell. The monofill has a "built-in" wind barrier, due to the construction of the monofill cells, which are partially below grade and considered "bermed."

Based on the emission inventory prepared for the SME-HGS facility, the inactive ash storage pile is estimated to emit 1.62 tons per year of PM_{10} (based on conservative emission calculation equations). All of the additional controls identified in the application for this permit yield minimal particulate removal with extremely high cost effective values. Detailed information regarding the cost analysis is contained in the application for this permit action. Therefore, the BACT analysis eliminates these methodologies on an economic basis. Although the RBLC database does not explicitly show any BACT determinations for ash storage or disposal in a monofill, the Department determined that an inactive ash storage pile, with best management practices, including compaction and wet dust suppression as necessary (i.e., water truck application) constitutes BACT in this case.

The proposed BACT technologies conform to similar sources recently permitted under the PSD program that are listed in the RBLC database. The data from the RBLC website is summarized in the application.

The Department determined that the affected material storage emission sources operating under the proposed control requirements and the established FFB and bin vent emission limit(s) of 0.005 gr/dscf and 0.01 gr/dscf, respectively, constitute BACT in this case. Further, the Department determined that the periodic PM/PM_{10} source testing and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted material storage BACT requirements.

C. Cooling Tower PM/PM_{10} Emissions BACT Analysis and Determination

A wet cooling tower will be used at the SME-HGS facility to dissipate waste heat from the generating system. The proposed cooling tower will be a fan-induced draft, counter-flow design. Latent heat of water evaporation is used to provide the cooling effect. The design circulating water rate is 102,800 gallons per minute (gpm). Approximately 2,250 gpm of the cooling water will be evaporated by the cooling tower.

The cooling tower provides direct contact between the cooling water flow and air passing through the tower. Some of the cooling water becomes entrained in the air stream and carried out of the tower as water droplets (in liquid phase). Water lost in the liquid phase is known as “drift.” The drift loss is independent of water lost to evaporation. When the drift droplets evaporate, dissolved solids crystallize and create particulate emissions. The particulate emissions consist of mineral matter and chemicals used for corrosion control in the piping systems. PM/PM_{10} emissions from the cooling tower are estimated in the emissions inventory at 13.5 tons per year.

Factors that affect PM/PM_{10} emission rates from wet cooling towers include: air and water flow patterns, the amount of total dissolved solids (TDS) in the cooling cycle water, circulating water volumes, the number of cooling tower concentration cycles and operation and maintenance practices.

1. Identification of Available PM/PM_{10} Control Strategies/Technologies

The Department is only aware of one control technology for PM_{10} emissions from wet cooling towers: drift eliminators. Drift eliminators work by intercepting as many water droplets as possible from the airflow leaving the cooling tower, thus minimizing PM_{10} emissions. Drift eliminators are designed to cause sudden directional changes to the air flow and the inertia of the water droplets causes them to impact the eliminator surfaces. The drift is then collected and returned to the cooling water flow. The drift eliminators also help minimize the amount of make-up water required for the cooling tower cycle operation. High efficiency drift eliminators of modern design can control the drift to less than 0.005% of the cooling tower circulating water flow.

2. Technical Feasibility Analysis

   Drift eliminators are technically feasible and commonly employed for wet cooling tower operations such as that proposed by SME-HGS.

3. Ranking of Available and Technically Feasible PM/PM_{10} Control Options by Efficiency

   Add-on PM/PM_{10} control would result in no additional control of PM/PM_{10} emissions resulting from wet cooling tower operations. The only available PM/PM_{10} control strategy/technology identified for the proposed cooling tower is a drift eliminator. Drift eliminators are capable of an approximate 90% reduction in particulate emissions resulting from wet cooling tower operations.

4. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

   The cooling tower design proposed by SME-HGS incorporates high efficiency drift eliminators. Because this control technology has the highest PM/PM_{10} control efficiency, no further analysis is required.

5. Cooling Tower PM/PM_{10} Emissions BACT Determination

   The top technology (drift eliminators), for cooling tower PM/PM_{10} control will reduce emissions by at least 90%. SME-HGS proposes to install, operate and maintain high efficiency drift eliminators on the cooling tower. The proposed design includes a drift rate of 0.002% circulating flow. The resulting potential PM/PM_{10} emission rate is 3.09 lb/hr, or 13.52 tons per year. This is equivalent to a normalized rate of 0.50 pounds of PM_{10} emitted per million gallons of circulating water (lbs/MMgal).

   The BACT determined PM/PM_{10} emission rate of 0.002% of circulating flow is one of the lowest values reported in the RBLC for other recently permitted and similar sources. The data from the RBLC website is summarized in the application.

   The Department determined that the installation, operation and maintenance of high efficiency drift eliminators on the cooling tower and a PM/PM_{10} emission limit of 0.002% of circulating flow constitute BACT in this case. Further, the Department determined that the periodic PM/PM_{10} source testing and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted material storage BACT requirements.

D. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed BACT Analysis and Determination

The following BACT analysis evaluates NO_x, CO, SO_2, PM/PM_{10}, and VOC emissions from the intermittent and limited use of the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater for support and emergency operations at the SME-HGS facility.

The Auxiliary Boiler will run on #2 diesel fuel-oil, natural gas, or propane and will only be operated during startup, shutdown, commissioning of the CFB Boiler and during extended downtimes of the CFB Boiler during the winter months to aid in the prevention of freezing of the CFB Boiler components. The Emergency Generator and Emergency Fire Pump will run only on #2 diesel fuel oil and operate only during emergencies and during required equipment maintenance. The Coal Thawing Shed Heater will operate only on propane or natural gas during times when the coal is frozen in the coal train cars.

1. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed NO_x Emissions

NO_x will be formed during the combustion of natural gas, propane, or diesel fuel in the Auxiliary Boiler, Emergency Generator, Emergency Firewater Pump, and Coal Thawing Shed Heater. Three fundamentally different mechanisms produce NO_x during the combustion of hydrocarbon fuels. The formation of NO_x is dominated by the thermal mechanism, which involves the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most of the "thermal NO_x" is formed in the high temperature flame zone near the burners or in the combustion chambers. The amount of thermal NO_x formed is directly proportional to oxygen concentration, peak temperature, and time of exposure to peak temperature. Virtually all thermal NO_x is formed in the region of the flame at the highest temperature. Maximum thermal NO_x production occurs at a slightly lean fuel-to-air ratio due to the excess availability of oxygen for reaction with the nitrogen in the air and fuel.

A second mechanism for the formation of NO_x, termed "prompt NO_x," occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals present in the fuel. The prompt NO_x reactions occur within the flame and are usually negligible when compared to the amount of thermal NO_x. However, prompt NO_x levels may become significant when technologies are applied that control thermal NO_x to ultra-low levels.

A third mechanism, "fuel NO_x," stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. The contribution of this mechanism to the total NO_x depends entirely on the nitrogen content in the fuel. For natural gas, propane, and fuel oil, the contribution of fuel NO_x is usually negligible.

A. Identification of Available NO_x Control Strategies/Technologies

NO_x emissions from the Auxiliary Boiler, Emergency Generator, Emergency Firewater Pump, and Coal Thawing Shed Heater can be reduced by several different methods. The following list presents methods listed in the RACT/BACT/LAER database and other technologies that are applicable to natural gas combustion processes:

i. Selective Catalytic Reduction (SCR);
ii. Selective Non-Catalytic Reduction (SNCR);
iii. Low Temperature Oxidation (LoTOx);
iv. Dry Low NOX (Staged Combustion);
v. Non-Selective Catalytic Reduction (NSCR);
vi. Wet Controls;
vii. Innovative Catalytic Systems (SCONOX and XONON);
viii. Process Limitations; and
ix. Proper Design (no additional control).

These control technologies may be applied individually or in combination. A brief discussion of each type of control technology that was not presented in the Main Boiler NOx BACT is presented below.

i. SCR

A detailed discussion of SCR NO_x control technology is included in the CFB Boiler NO_x BACT analysis.

ii. SNCR

A detailed discussion of SNCR NO_x control technology is included in the CFB Boiler NO_x BACT analysis.

iii. Low Temperature Oxidation ($LoTO_x$)

Oxygen and nitrogen are injected at ~380°F to transform NO and NO_2 into N_2O_5 using an ozone generator and a reactor duct. N_2O_5, which is soluble, dissociates into N_2 and H_2O in a wet scrubber. Requirements of this system include a wet scrubber, oxygen, and a cooling water supply. Scrubber effluent treatment must also be provided. The estimated control efficiency of the system is 80-90%.

iv. Dry Low NO_x

Dry technologies may be identified as dry low NO_x (DLN) burners, dry low emissions (DLE), or $SoLoNO_x$. These technologies incorporate multiple stage combustors that may include premixing, fuel-rich zones that reduce the amount of O_2 available for NO_x production, fuel-lean zones that control NO_x production through lower combustion temperatures, or some combination of these. A quench zone may also be present to control gas temperature. Almost all new process heaters/boilers presently being manufactured incorporate these technologies into their combustor designs to some extent. These systems typically result in 40-60% reduction in NO_x.

v. Non-Selective Catalytic Reduction

An NSCR unit controls NO_x emissions by using available CO and residual hydrocarbons in the exhaust of a rich-burn internal combustion engine as an NO_x reducing agent. Without the catalyst, in the presence of oxygen, the hydrocarbons will be oxidized instead of reacting with the NO_x. As the excess hydrocarbon and NO_x pass over a honeycomb or monolithic catalyst (usually a combination of noble metals such as platinum, palladium, and/or rhodium), the reactants are reduced to N_2, H_2O, and CO_2.

The noble metal catalyst usually operates between 800°F and 1,200°F; therefore, the unit would normally be mounted near the engine exhaust to maintain a high enough temperature to allow the various reactions to occur. In order to achieve maximum performance, 80% to 90% reduction of NO_x concentration, the engine must burn a rich fuel mixture, causing the engine to operate less efficiently. The NSCR can only be applied to rich-burn engines and not to the Auxiliary Boiler.

vi. Wet Controls

Water or steam injection technology has been well demonstrated to suppress NO_x emissions from gas turbines, but it is not commonly used to control NO_x on process heaters or boilers. The injected fluid increases the thermal mass by dilution and thereby reduces peak temperatures in the flame zone. NO_x reduction efficiency increases as the water-to-fuel ratio increases. For maximum efficiency, the water must be atomized and injected with homogeneous mixing throughout the combustor. This technique reduces thermal NO_X, but may actually increase the production of fuel NO_x. Depending on the initial NO_x levels, wet injection may reduce NO_x by 60% or more.

vii. Innovative Catalytic Systems

Innovative catalytic technologies integrate catalytic oxidation and absorption technology. In the SCONO$_x$ process, CO and NO are catalytically oxidized to CO_2 and NO_x; the NO_2 molecules are subsequently absorbed on the treated surface of the SCONO$_x$ catalyst. Ammonia is not required. The limited emissions data for this process reflects that there is an associated increase in HAP emissions when applying this technology. SCONO$_x$ technology has recently been applied to combined cycle turbine generation facilities, since steam produced by a heat recovery steam generator (HRSG) is required in the process.

The XONON system is applicable to diffusion and lean-premix combustors. It utilizes a flameless combustion system where fuel and air react on a catalyst surface, preventing the formation of NO_X while achieving low CO and unburned hydrocarbon emission levels. The overall combustion system consists of the partial combustion of the fuel in the catalyst module followed by completion of combustion downstream of the catalyst. Initial partial combustion produces no NO_x and downstream combustion occurs in a flameless homogeneous reaction that produces almost no NO_x. The system is totally contained within the combustor and is not an add-on control device. This technology has not been fully demonstrated.

viii. Process Limitations

The amount of NO_x and other pollutants formed by fossil fuel combustion can be reduced proportionately by limiting operating hours or reducing fuel consumption.

B. Technical Feasibility Analysis

Innovative catalytic systems typically installed on combustion turbines are technically infeasible to install on the Auxiliary Boiler, Emergency Generator, Emergency Firewater Pump, and Coal Thawing Shed Heater.

LoTOx and wet controls are technically impractical on the Auxiliary Boiler, Emergency Generator, Emergency Firewater Pump, and Coal Thawing Shed Heater as these types of control options have never been installed on emergency use equipment and equipment in intermittent use. SCR and SNCR are classified as technically infeasible on small emergency use equipment. These controls are brought forward for the Auxiliary Boiler and Coal Thawing Shed Heater since these units are planned to operate more frequently and potentially for longer durations than the emergency equipment.

DLN technology is technically infeasible on spark or compression ignition reciprocating internal combustion engines. Therefore, DLN is eliminated from use on the Emergency Generator and Emergency Firewater Pump.

NSCR technology is technically infeasible on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because an NSCR technology requires a lean oxygen exhaust stream (<1% O2). These four units will operate with a rich oxygen exhaust stream.

C. Ranking of Available and Technically Feasible NO_x Control Options by Efficiency

The following table ranks the available and technically feasible control options according to control effectiveness and includes the no additional add-on control and process limitations control strategies.

NO_x Control Option	Auxiliary Boiler and Coal Thawing Shed Heater Control Efficiency	Emergency Generator and Emergency Fire Water Pump Control Efficiency
SCR	80-90%	Technically Infeasible
NSCR	Technically Infeasible	Technically Infeasible
DLN (Auxiliary Boiler only)	40-60%	Technically Infeasible (Except Coal Thawing Shed Heater)
SNCR	40-60%	Technically Infeasible
Process Limitations	Varies with Limitation	Varies with Limitation
Proper Design (no additional Control	N/A	N/A

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

No environmental or energy impacts exist for the NO_x control options for the Auxiliary Boiler or Coal Thawing Shed Heater that would eliminate the control option. The application provides a detailed economic evaluation for the Auxiliary Boiler. No economic cost analysis is provided for the Coal Thawing Shed Heater because the only add-on control option is a DLN burner, which will be employed on the heater.

The control efficiency used for the SCR was 90%, SNCR was 50%, and DLN was 50%. The DLN equipment cost for the Auxiliary Boiler was provided by Nebraska Boilers, and the DLN equipment cost for the Coal Thawing Shed Heater was based on a ratio of the Auxiliary Boiler DLN cost and the heat input values for the Auxiliary Boiler and Coal Thawing Shed Heater. The SCR and SNCR equipment costs were derived from equations in OAQPS Section 4 – NO_x Controls (10/2000). Capital costs were annualized at 10% for 10 years as recommended by OAQPS. As reported in the application, the Auxiliary Boiler cost effective value for SCR is approximately $36,925/ton of NO_x removed; for SNCR the cost effective value is approximately $18,514/ton NO_x removed; and for DLN the cost effective value is approximately $1341/ton NO_x removed. The Coal Thawing Shed Heater cost effective value for SCR is approximately $158,172/ton of NO_x removed; for SNCR the cost effective value is approximately $179,635/ton NO_x removed; and for DLN the cost effective value is approximately $16,678/ton NO_x removed. Based on the cost-effective values provided above, the Department determined that DLN constitutes a cost-effective control option for the Auxiliary Boiler in this case. Further, based on the cost-effective values provided above, all control options are deemed economically infeasible for the Coal Thawing Shed Heater in this case. A detailed cost analysis is included in the application for this air quality permit.

E. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed NO_x Emissions BACT Determination

Based on the annual cost-effectiveness of DLN, the Department determined that NO_x BACT control for the Auxiliary Boiler is DLN burners with process limits in this case. Further, based on Department verified information contained in the application for this air quality permit and the NO_x BACT analysis summarized previously, the Department determined that NO_x BACT for the Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater is proper design and combustion practices and process limitations. The unit specific process limitations are included in the following table.

Combustion Unit	**Process Limitation**	**Annual Hours of Operation**
Auxiliary Boiler	Start-Up, Shutdown and Commissioning Operation Only	850
Emergency Generator	Emergency Use and Required Equipment Maintenance Operation Only	500
Emergency Fire Water Pump	Emergency Use and Required Equipment Maintenance Operation Only	500
Coal Thawing Shed Heater	Necessary Coal Thawing Operation Only	240

SME-HGS did not propose any NO_x emission limits (BACT or otherwise) on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because these units will only operate during limited situations. The Department determined that the enforceable process limits and fuel specifications constitute BACT for the affected units. Further, the Department determined that the Emergency Fire Water Pump and Coal Thawing Shed Heater operations do not warrant emission limitations due to limited potential NO_x impact associated with enforceable limitations. However, in order to protect the ambient air quality impact analysis conducted for this air quality permit, the Department determined that non-BACT NO_x emission limit(s) of 46.79 lb/hr (1-hr averaging time) for the Auxiliary Boiler and 41.20 lb/hr (1-hr averaging time) for the Emergency Generator are necessary.

2. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed CO Emissions

A. Identification of Available CO Control Strategies/Technologies

Control of CO and VOC can be achieved through oxidation of post-combustion gases with or without a catalyst. The following is a list of available CO control technologies:

i. Oxidation Catalyst;
ii. Thermal Oxidation;
iii. NSCR;
iv. Process Limitations; and
v. Proper Design (no additional control).

The oxidation catalyst and thermal oxidation control options are described in detail in the CFB Boiler BACT analysis. NSCR has been described in the NO_x BACT analysis in the previous section. NSCR has the ability to control NO_x and CO from rich-burn internal combustion engines.

B. Technical Feasibility Analysis

NSCR technology is technically infeasible on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because an NSCR technology requires a lean oxygen exhaust stream (<1% O2). These four affected units will operate with a rich oxygen exhaust stream. The other available CO control options are technically feasible.

C. Ranking of Available and Technically Feasible CO Control Options by Efficiency

The following table ranks the control options according to control effectiveness.

CO Control Options for Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater	**Percent Reduction**
Catalytic Oxidation	80-90%
Thermal Oxidation	80-90%
Process Limitation	Varies with Limitation
Proper Design and Operation (no add-on control)	N/A

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

No environmental or energy impacts exist for the CO control options for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater that would eliminate the control option. The application for this air quality permit provides an economic evaluation for the four affected emitting units. The control efficiency for thermal and catalytic incineration is 90% and equipment costs were derived from the equation in OAQPS Chapter 2 – Incinerators (9/2000). Capital costs were annualized at 10% for 10 years as recommended by OAQPS. As reported in the application, the Auxiliary Boiler cost effective value for thermal oxidation is approximately $78,794/ton of CO removed and the catalytic oxidation cost effective value is approximately $64,829/ton CO removed. The Emergency Generator cost effective value for thermal oxidation is approximately $157,653/ton of CO removed and the catalytic oxidation cost effective value is approximately $280,198/ton CO removed. The Emergency Fire Water Pump cost effective value for thermal oxidation is approximately $354,202/ton of CO removed and the catalytic oxidation cost effective value is approximately $585,551/ton CO removed. The Coal Thawing Shed Heater cost effective value for thermal oxidation is approximately $163,320/ton of CO removed and the catalytic oxidation cost effective value is approximately $253,926/ton CO removed. Based on the cost-effective values provided above, all control options are deemed economically infeasible for the affected units in this case. A detailed cost analysis is included in the application for this air quality permit.

E. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed CO Emissions BACT Determination

Based on Department verified information contained in the application for this air quality permit and the CO BACT analysis summarized previously, the Department determined that CO BACT for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed is proper design and combustion practices and the process limitations included in the following table.

Combustion Unit	**Process Limitation**	**Annual Hours of Operation**
Auxiliary Boiler	Start-Up, Shutdown and Commissioning Operation Only	850
Emergency Generator	Emergency Use and Required Equipment Maintenance Operation Only	500
Emergency Fire Water Pump	Emergency Use and Required Equipment Maintenance Operation Only	500
Coal Thawing Shed Heater	Necessary Coal Thawing Operation Only	240

SME-HGS did not propose any CO emission limits (BACT or otherwise) on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because these units will only operate during limited situations. The Department determined that the enforceable process limits and fuel specifications constitute BACT for the affected units. Further, the Department determined that the Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater operations do not warrant emission limitations due to limited potential CO impact associated with enforceable limitations. However, in order to protect the ambient air quality impact analysis submitted with the application for this air quality permit, the Department determined that a non-BACT CO emission limit of 18.6 lb/hr (1-hr averaging time) for the Auxiliary Boiler is necessary.

3. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed SO_2 Emissions

A. Identification of Available SO_2 Control Strategies/Technologies

The following is a list of available SO_2 control technologies.

i. Wet or dry FGD;
ii. Low sulfur fuels;
iii. Process limitations; and
iv. No additional control.

Wet and dry flue gas desulfurization control options are described in the SO_2 CFB Boiler BACT. Using low sulfur fuels such as propane, pipeline quality natural gas, and low sulfur diesel is an effective SO_2 emissions control strategy.

B. Technical Feasibility Analysis

Wet and dry FGD on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater are considered technically infeasible because these emitting units will be intermittently operating on gaseous or liquid fuel with low sulfur concentrations. Wet and dry FGD are typically employed on solid fuel or gaseous and liquid fuel that have high sulfur contents and high potential SO_2 emissions. Natural gas, propane, and #2 diesel fuel oil are required by regulation to have relatively low sulfur concentrations. Therefore, the Department determined that wet and dry FGD control options are considered technically infeasible for the control of SO_2 from the affected units in this case.

C. Ranking of Available and Technically Feasible SO_2 Control Options by Efficiency

The following table ranks the available and feasible SO_2 control options according to control effectiveness.

SO_2 Control Options	**Percent Reduction**
Low Sulfur Fuels	Varies
Process Limitations	Varies with Limitation
No Additional Controls	N/A

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

No economic, environmental, or energy impacts exist for the available and feasible SO_2 control options that would eliminate the control options from further evaluation. An economic analysis is not provided for the remaining control options listed because SME-HGS proposed the use of low sulfur fuels and process limitations.

E. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed SO_2 Emissions BACT Determination

Based on Department verified information contained in the application for this air quality permit and the SO_2 BACT analysis summarized previously, the Department determined that SO_2 BACT for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed is the combustion of low sulfur fuels only and the process limitations included in the following table.

Combustion Unit	Process Limitation	Annual Hours of Operation
Auxiliary Boiler	Start-Up, Shutdown and Commissioning Operation Only	850
Emergency Generator	Emergency Use and Required Equipment Maintenance Operation Only	500
Emergency Fire Water Pump	Emergency Use and Required Equipment Maintenance Operation Only	500
Coal Thawing Shed Heater	Necessary Coal Thawing Operation Only	240

SME-HGS did not propose any SO_2 emission limits (BACT or otherwise) on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because these units will only operate during limited situations. The Department determined that the enforceable process limits and fuel specifications constitute BACT for the affected units. Further, the Department determined that the Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater operations do not warrant emission limitations due to limited potential SO_2 impact associated with enforceable limitations. However, in order to protect the ambient air quality impact analysis submitted with the application for this air quality permit, the Department determined that an effects-based non-BACT SO_2 emission limit of 12.63 lb/hr (3-hr averaging time) for the Auxiliary Boiler is necessary.

4. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed PM/PM_{10} Emissions

A. Identification of Available PM/PM_{10} Control Strategies/Technologies

The following is a list of available PM/PM10 control technologies.

i. Fabric Filter Baghouse;
ii. Electrostatic Precipitator;
iii. Low Ash Fuels;
iv. Process Limitations; and
v. No Additional Control.

Fabric filter baghouses and ESPs are described in the PM/PM_{10} Main Boiler BACT.

B. Technical Feasibility Analysis

Fabric filter baghouses are technically infeasible control options for the emergency generator and emergency fire water pump because the exhaust temperature is too hot for fabric filter bags. The remaining available control options are assumed to be technically feasible for the Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater. All of the available control options are technically feasible for the Auxiliary Boiler.

C. Ranking of Available and Technically Feasible PM/PM_{10} Control Options by Efficiency

The following table ranks the available and feasible PM/PM_{10} control options according to control effectiveness.

PM/PM_{10} Control Technology	**Percent Reduction**
FFB (Auxiliary Boiler and Coal Thawing Shed)	99%+
ESP (Auxiliary Boiler and Coal Thawing Shed)	99%+
Low Ash Fuels	Varies with Limitation
Process Limitations	Varies with Limitation
No Additional Controls	N/A

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

No environmental, or energy impacts exist for the PM/PM_{10} control options that would eliminate the control options for any of the affected emitting units. An economic impact analysis is provided for FFB and ESP control options for the Auxiliary Boiler and Coal Thawing Shed Heater based on cost data provided in the EPA fact sheets for FFB and ESP control. As reported in the application, the Auxiliary Boiler cost-effective value for FFB is approximately $153,981/ton PM/$PM_{10}$ removed and the cost-effective value for ESP is approximately $230,971/ton PM/$PM_{10}$ removed. The Coal Thawing Shed Heater cost-effective value for FFB is approximately $922,141/ton PM/$PM_{10}$ removed and the cost-effective value for ESP is approximately $1,383,212/ton PM/$PM_{10}$ removed. Based on the cost-effective values provided above, all control options are deemed economically infeasible for the affected units in this case. A detailed cost analysis is included in the application for this air quality permit.

E. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed PM/PM_{10} Emissions BACT Determination

Based on Department verified information contained in the application for this air quality permit and the PM/PM_{10} BACT analysis summarized previously, the Department determined that PM/PM_{10} BACT for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed is process limitations, as indicated in the following table.

Combustion Unit	**Process Limitation**	**Annual Hours of Operation**
Auxiliary Boiler	Start-Up, Shutdown and Commissioning Operation Only	850
Emergency Generator	Emergency Use and Required Equipment Maintenance Operation Only	500
Emergency Fire Water Pump	Emergency Use and Required Equipment Maintenance Operation Only	500
Coal Thawing Shed Heater	Necessary Coal Thawing Operation Only	240

SME-HGS did not propose any PM/PM_{10} emission limits (BACT or otherwise) on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because these units will only operate during limited situations. The Department determined that the enforceable process limits and fuel specifications constitute BACT for the affected units. Further, the Department determined that the Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater operations do not warrant emission limitations due to limited potential PM/PM_{10} impact associated with enforceable limitations. However, in order to protect the ambient air quality impact analysis submitted with the application for this air quality permit, the Department determined that a non-BACT PM/PM_{10} emission limit of 3.22 lb/hr (24-hr averaging time) for the Auxiliary Boiler is necessary.

5. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed VOC Emissions

A. Identification of Available VOC Control Strategies/Technologies

Control of VOC and CO can be achieved through oxidation of post-combustion gases with or without a catalyst. The following is a list of available VOC control technologies.

i. Oxidation Catalyst;
ii. Thermal Oxidation;
iii. Process Limitations; and
iv. Proper Design (no additional control).

The oxidation catalyst and thermal oxidation VOC control options are described in detail in the CFB Boiler BACT analysis.

B. Technical Feasibility Analysis

Thermal and catalytic oxidation as well as process limits are considered technically feasible for all of the affected units.

C. Ranking of Available and Technically Feasible VOC Control Options by Efficiency

The following table ranks the control options according to control effectiveness.

VOC Control Options for Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater	**Percent Reduction**
Catalytic Oxidation	80-90%
Thermal Oxidation	80-90%
Process Limitation	Varies with Limitation
Proper Design and Operation (no add-on control)	N/A

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

No environmental or energy impacts exist for the VOC control options for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater that would eliminate the control option. The application for this air quality permit provides an economic evaluation for the four affected emitting units. As reported in the application, the Auxiliary Boiler cost effective value for thermal oxidation is approximately $1,198,837/ton of VOC removed and the catalytic oxidation cost effective value is approximately $983,985/ton VOC removed. The Emergency Generator cost effective value for thermal oxidation is approximately $1,206,310/ton of VOC removed and the catalytic oxidation cost effective value is approximately $980,693/ton VOC removed. The Emergency Fire Water Pump cost effective value for thermal oxidation is approximately $3,317,579/ton of VOC removed and the catalytic oxidation cost effective value is approximately $4,098,854/ton VOC removed. The Coal Thawing Shed Heater cost effective value for thermal oxidation is approximately $2,462,650/ton of VOC removed and the catalytic oxidation cost effective value is approximately $3,724,499/ton VOC removed. Based on the cost-effective values provided above, all control options are deemed economically infeasible for the affected units in this case. A detailed cost analysis is included in the application for this air quality permit.

E. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed VOC Emissions BACT Determination

Based on Department verified information contained in the application for this air quality permit and the VOC BACT analysis summarized previously, the Department determined that VOC BACT for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed is proper design with process limitations, included in the following table.

Combustion Unit	**Process Limitation**	**Annual Hours of Operation**
Auxiliary Boiler	Start-Up, Shutdown and Commissioning Operation Only	850
Emergency Generator	Emergency Use and Required Equipment Maintenance Operation Only	500
Emergency Fire Water Pump	Emergency Use and Required Equipment Maintenance Operation Only	500
Coal Thawing Shed Heater	Necessary Coal Thawing Operation Only	240

SME-HGS did not propose any VOC emission limits (BACT or otherwise) on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because these units will only operate during limited situations. The Department determined that the enforceable process limits and fuel specifications constitute BACT for the affected units. Further, the Department determined that the affected unit operations do not warrant emission limitations due to limited potential VOC impact associated with enforceable limitations.

E. Vehicle Traffic/Haul Roads PM/PM_{10} Emissions BACT Analysis and Determination

Fugitive PM/PM_{10} emissions will be generated at the SME-HGS facility by vehicle travel in and around the plant site. The Department determined that SME-HGS must use reasonable precautions to limit the fugitive emissions of airborne particulate matter on haul roads, access roads, parking areas, and the general plant property. SME-HGS proposed to pave the roads and parking areas around the main complex of buildings at the site to allow for unimpeded traffic flow during wet and muddy conditions. The roads further from the site complex (e.g., the haul road to the ash monofill) will be unpaved.

As previously discussed, SME-HGS proposed to use a combination of paved and unpaved roads at the site. The Department determined that best management practices including the application of water and/or chemical dust suppressants, as necessary, to the unpaved roads and the sweeping of paved roads, as necessary, constitutes BACT in this case. This is common industry practice and is typically considered BACT for fugitive road dust resulting from vehicle traffic at industrial sites.

F. CFB Boiler Refractory Brick Curing Heaters (2771 MMBtu/hr)

Section II.M.1-4 of the supplemental preliminary determination incorporates enforceable operational limits and a maximum heat input capacity limit for the proposed propane-fired CFB Boiler refractory curing heater(s). Because these enforceable operational limits restrict the allowable operating time, type of fuel, and heat input capacity of the affected units, potential emissions of all regulated pollutants from CFB Boiler refractory brick curing heater(s) operations are limited. Given the limited potential to emit of the CFB Boiler refractory curing heater(s), the Department determined that add-on control equipment would be cost prohibitive. Therefore, the Department determined that normal operation within the permit limits contained in Section II.M of the supplemental preliminary determination constitutes BACT for the affected unit(s), in this case.

The control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

IV. Emission Inventory

ton/year											
Emission Source	**PM**	**PM_{10}**	**NO_x**	**SO_x**	**CO**	**VOC**	**Pb**	**Hg**	**HCl**	**HF**	**H_2SO_4**
CFB Boiler (2626 MMBtu/hr)	138.0*	299.1	805.2	437.1	1150.2	34.5	0.28	0.017	24.15	19.55	62.11
Aux. Boiler (225 MMBtu/hr)	1.4	1.4	19.9	5.4	7.9	0.5	---	---	---	---	---
Emergency Generator	0.13	0.13	10.3	0.3	0.7	0.2	---	---	---	---	---
Emergency Fire Water Pump	0.04	0.04	0.9	0.03	0.2	0.03	---	---	---	---	---
Coal Thawing Shed	0.03	0.03	1.0	0.00	0.17	0.03	---	---	---	---	---
Car Unloading Baghouse (DC1)	24.4	24.4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal Silo Baghouse (DC2)	3.6	3.6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal Crusher Baghouse (DC3)	2.8	2.8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tripper System Baghouse (DC4)	3.8	3.8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Limestone Baghouse (DC5)	5.0	5.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fly-Ash Silo Bin Vent (DC6)	1.5	1.5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bed-Ash Silo Bin Vent (DC7)	1.4	1.4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal Pile Dressing	1.7	0.3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergency Coal Pile Transfers	3.4	1.6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergency Coal Pile Storage	3.3	1.6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ash Landfill (Truck Dump)	3.2	1.6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower	13.53	13.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Heavy Truck Traffic	4.8	1.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Building Heaters	0.28	0.28	9.72	0.01	1.32	0.35	---	---	---	---	---
Fuel Oil Storage Tank	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00
Refractory Brick Curing Heaters (2771 MMBtu/hr)	3.05	3.05	96.65	0.09	16.28	2.36	---	---	---	---	---
Total Emissions	**215**	**366**	**944**	**443**	**1177**	**38**	**0.28**	**0.02**	**24.15**	**19.55**	**62.11**
* CFB Boiler PM emissions represent only front-half filterable PM emissions. Total PM emissions including PM_{10} and condensable PM emissions are estimated under the column for CFB Boiler PM_{10} emissions.											
A complete emission inventory for Permit #3423-00 is on file with the Department											

CFB Boiler Emissions

Heat Input: 2626.1 MMBtu/hr (Average Annual Heat Input – SME-HGS Information)
Hours of Operation: 8760 hr/yr (Annual Potential)

Filterable PM Emissions

Emission Factor: 0.012 lb/MMBtu (BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.012 lb/MMBtu = 31.51 lb/hr
31.51 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 138.03 ton/yr

PM_{10} Emissions (filterable and condensable)

Emission Factor: 0.026 lb/MMBtu (BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.026 lb/MMBtu = 68.28 lb/hr
68.28 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 299.06 ton/yr

NO_x Emissions

Emission Factor: 0.07 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.07 lb/MMBtu = 183.83 lb/hr
183.83 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 805.16 ton/yr

SO_x Emissions

Emission Factor: 0.038 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.038 lb/MMBtu = 99.79 lb/hr
99.79 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 437.09 ton/yr

CO Emissions

Emission Factor: 0.10 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.10 lb/MMBtu = 262.61 lb/hr
262.61 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 1150.23 ton/yr

VOC Emissions

Emission Factor: 0.003 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.003 lb/MMBtu = 7.88 lb/hr
7.88 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 34.51 ton/yr

Hg Emissions

Emission Factor: 1.50E-06 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 1.50E-06 lb/MMBtu = 0.0039 lb/hr
0.0039 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.017 ton/yr

HCl Emissions

Emission Factor: 0.0021 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.0021 lb/MMBtu = 5.51 lb/hr
5.51 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 24.15 ton/yr

HF Emissions

Emission Factor: 0.0017 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.0017 lb/MMBtu = 4.46 lb/hr
4.46 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 19.55 ton/yr

H_2SO_4 Emissions

Emission Factor: 0.0054 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.0054 lb/MMBtu = 14.18 lb/hr
14.18 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 62.11 ton/yr

V. Existing Air Quality

The air quality classification for the SME-HGS project area is "Unclassifiable or Better than National Standards" (40 CFR 81.327) for the National Ambient Air Quality Standards (NAAQS) for all criteria pollutants. However, the facility will locate in an area that has recently been re-designated attainment for CO under a limited maintenance plan. The SME-HGS facility has not been identified in any studies as impacting the previous CO nonattainment area.

Under the requirements of the PSD program, SME-HGS was required to conduct modeling to determine pollutant-specific pre-monitoring applicability. Because air modeling showed that the concentration of PM_{10} exceeded the level identified in ARM 17.8.818(7), SME-HGS was required to conduct on-site pre-monitoring for this pollutant. SME-HGS collected PM_{10} pre-monitoring data at the proposed site from November 12, 2004, through November 11, 2005. The following table lists the background monitoring data from the SME-HGS PM_{10} monitoring site. The measured PM_{10} values establish the baseline concentrations and demonstrate compliance with all applicable ambient air quality standards.

PM_{10} Pre-monitoring Results

Pollutant	Avg. Period	High Impact (ppm)	High Impact ($\mu g/m^3$)	HSH Impact (ppm)	HSH Impact ($\mu g/m^3$)	Ambient Standard[a] ($\mu g/m^3$)	% of Standard
PM_{10}	24-hr	------	23	------	19	150	13
	Annual	------	7	------	------	50	14

[a] MAAQS and NAAQS

VI. Ambient Air Impact Analysis

The nearest PSD Class I area is the Gates of the Mountains Wilderness Area located approximately 53 miles [85 kilometers (km)] southwest of the proposed site. Impacts have also been evaluated at the following other Class I areas within 250 km of the site: Scapegoat Wilderness Area, Bob Marshall Wilderness Area, Glacier National Park, Mission Mountains Wilderness Area, UL Bend Wilderness Area, and Anaconda Pintler Wilderness Area. Bison Engineering, Inc. (Bison) submitted modeling on behalf of SME-HGS.

Emissions of NO_x, SO_2, CO, PM_{10} and Pb were modeled to demonstrate compliance with the NAAQS and Montana Ambient Air Quality Standards (MAAQS) and the PSD increments. The modeling was performed in accordance with the methodology outlined in the Draft New Source Review Workshop Manual, EPA, October 1990 (NSR Manual), and Appendix W of 40 CFR 51, Guideline on Air Quality Models (revised), April 15, 2003. SME-HGS's Class II modeling used five years of surface and upper air meteorological data (1987-1991) collected at the Great Falls Airport National Weather Service (NWS) station.

SME-HGS submitted a significant impact analysis based on emissions from all proposed SME-HGS sources, including the CFB Boiler refractory brick curing heater(s) proposed under the supplemental preliminary determination. The modeled SME-HGS impacts are compared to the applicable Class II significant impact levels (SIL's) in Table 1. The SILs are contained in Table C-4 of the NSR Manual. The impacts exceed the SIL's for PM_{10}, NO_x and SO_2; therefore, a cumulative impact analysis is required for these pollutants to demonstrate compliance with the NAAQS/MAAQS. The radius of impact (ROI) for each pollutant and averaging period is included in Table 1.

Table 1: SME Class II Significant Impact Modeling

Pollutant	Avg. Period	Modeled Conc. (μg/m^3)	Class II SIL[a] (μg/m^3)	Significant (y/n)	Radius of Impact (km)
PM_{10}	24-hr	18.7	5 (1)[b]	Y	3.0
	Annual	3.1	1	Y	1.4
NO_x [c]	Annual	1.6	1	Y	0.7
CO	1-hr	66.2	2,000	N	------
	8-hr	26.9	500	N	------
SO_2	3-hr	13.6	25	N	------
	24-hr	7.4	5 (1)[b]	Y	0.7
	Annual	0.24	1	N	------
O_3	Net Increase of VOC: 35.6 tpy. Less than 100 tpy, source is exempt from O_3 analysis.				

[a] All concentrations are 1st-high for comparison to SIL's.
[b] If a proposed source is located w/in 100 km of a Class I area, an impact of 1 μg/m^3 on a 24-hour basis is significant.
[c] Significant impact area (SIA) based on NO_x impact (rather than NO_2).

NAAQS/MAAQS modeling was conducted for PM_{10}, SO_2, and NO_x. CO impacts from SME-HGS alone were below the modeling significance level and no additional modeling was conducted for CO emissions. The full ambient impact analysis included emissions from other industrial sources in the Great Falls area.

Modeling results are compared to the applicable NAAQS/MAAQS in Table 2. Modeled concentrations show the impacts from SME-HGS and off-site sources and include the background values. As shown in Table 2, the modeled concentrations are below the applicable NAAQS/MAAQS.

Table 2: SME-HGS NAAQS/MAAQS Compliance Demonstration

Pollu-tant	Avg. Period	Modeled Conc.[a] ($\mu g/m^3$)	Backgrnd Conc. ($\mu g/m^3$)	Ambient Conc. ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	% of NAAQS	MAAQS ($\mu g/m^3$)	% of MAAQS
PM_{10}	24-hr	10.5	23	33.5	150	22	150	22
	Annual	3.2	7	10.2	50	20	50	20
NO_2	1-hr	240[b]	75	315	------	------	564	56
	Annual	2.0[c]	6	8.0	100	8.0	94	8.5
SO_2	1-hr	87.2	35	122	------	------	1,300	9.4
	3-hr	42.7	26	68.7	1,300	5.3	------	-----
	24-hr	6.3	11	17.3	365	4.7	262	6.6
	Annual	0.8	3	3.8	80	4.8	52	7.3
Pb	Quarterly[d]	0.0005	Not. Avail.	0.0005	1.5	0.03		
	90-day[d]	0.0005	Not. Avail.	0.0005	-----	-----	1.5	0.03

[a] Concentrations are high-second high values except annual averages and SO_2 1-hr, which is high-6th-high.
[b] One-hour NOx impact is converted to NO_2 by applying the ozone limiting method, as per DEQ guidance.
[c] Annual NOx is converted to NO_2 by applying the ambient ratio method, as per DEQ guidance.
[d] SME reported the 24-hour average impact for compliance demonstration.

Cumulative impact modeling, including emissions from all PSD increment-consuming sources in the Great Falls area, was used to demonstrate compliance with the Class II PSD increments for PM_{10}, NO_x and SO_2. Class II increment modeling results are compared to the applicable PSD increments in Table 3.

Table 3: Class II PSD Increment Compliance Demonstration

Pollutant	Avg. Period	Met Data Set	Modeled Conc. ($\mu g/m^3$)	Class II Increment ($\mu g/m^3$)	% Class II Increment Consumed	Peak Impact Location (UTM Zone 12)
PM_{10}	24-hr	Great Falls 1988	10.5	30	35%	(497701, 5266846)
	Annual	Great Falls 1987	3.2	17	19%	(497701, 5267036)
SO_2	3-hr	Great Falls 1987	11.0	512	2.1%	(497100, 526076)
	24-hr	Great Falls 1991	6.3	91	6.9%	(497290, 5268077)
	Annual	Great Falls 1987	0.4	20	2.0%	(497386, 5268078)
NO_2	Annual[b]	Great Falls 1988	1.7	25	6.8%	(497386, 5268078)

a – Compliance with short-term standards is based on high-second-high impact.
b – Annual NO_x impacts are compared to the NO_2 standards.

SME-HGS submitted CALPUFF modeling to determine concentration, visibility and deposition impacts at the Class I areas within 250 km of the project site. CALMET was used to prepare meteorological data for input to CALPUFF. Meteorological data inputs to CALMET are included in Table 4.

Table 4: CALPUFF MET Data

Input Data Parameter	Model Year		
	1990	1992	1996
Number of Surface Stations	14	13	13
Number of Upper Air Stations	7	7	5
Number of Precipitation Stations	98	99	92
MM4/MM5 Data Grid Size	80 km	80 km	36 km

SME-HGS modeled PM_{10}, SO_2, and NO_x emissions from the SME-HGS project, and compared SME-HGS impacts to EPA's proposed Class I SIL's. SME-HGS's impacts exceeded the Class I SO_2 SILs at the Gates of the Mountain and Scapegoat Wilderness Areas. Modeling of PM_{10} and NO_x emissions did not show any exceedances of the Class I SILs at any of the Class I areas. Cumulative impact modeling for SO_2, including all PSD increment-consuming sources, was provided for the Class I areas. Results of the Class I cumulative impact modeling are included in Table 5 and show that the cumulative modeled concentrations are lower than the Class I PSD increments.

Table 5: Class I PSD Increment Compliance Demonstration, Peak Impacts

Pollutant	Avg. Period	Met Data Period	SME Modeled Conc. ($\mu g/m^3$)	Non-SME Modeled Conc. ($\mu g/m^3$)	Total Modeled Conc. ($\mu g/m^3$)	% Class I Increment Consumed
Gates of the Mountains						
SO_2	3-hr	July 23, 1996	1.08	1.26	2.34	9.4%
	24-hr	March 5, 1996	0.25	0.29	0.54	11%
Scapegoat Wilderness Area						
SO_2	24-hr	April 11, 1990	0.21	0.36	0.57	11%

a – Compliance with short-term standards is based on high-first-high impact.

SME-HGS used the CALPUFF modeling results and the CALPOST program to determine deposition values in the Class I areas. The results are shown in Table 6 and are compared to the deposition level of concern identified in the Federal Land Managers Air Quality Related Values Workgroup (FLAG) Phase I Report (December 2000). None of the modeled deposition impacts exceeded the FLAG level of concern. The Department concluded that no additional analysis of deposition impacts is needed.

Table 6: SME-HGS CALPUFF Deposition Modeling Results

Class I Area	1990		1992		1996	
	N (kg/ha/yr)	S (kg/ha/yr)	N (kg/ha/yr)	S (kg/ha/yr)	N (kg/ha/yr)	S (kg/ha/yr)
Ana-Pintler	0.0003	0.0004	0.0001	0.0002	0.0002	0.0002
Bob Marsh.	0.001	0.001	0.001	0.001	0.001	0.001
Gates Mtns.	0.002	0.002	0.002	0.002	0.002	0.003
Glacier NP	0.0003	0.0003	0.0003	0.0003	0.001	0.001
Mission Mtns	0.0002	0.0003	0.0005	0.001	0.0004	0.001
Scapegoat	0.001	0.001	0.001	0.001	0.002	0.002
UL Bend	0.002	0.002	0.001	0.002	0.002	0.002
FLAG Level of Concern	0.005	0.005	0.005	0.005	0.005	0.005

SME-HGS provided an analysis of the impact of the proposed project on air quality related values (AQRV) in the Class I and Class II areas. The effects of deposition on sensitive plant species and the effects of trace elements deposition on soils, plants, and animals were found to be below guideline levels contained in the USEPA screening guideline (EPA 450/2-81-078). The Department and affected FLMs have concluded that lake acidification analyses were not necessary because there are no sensitive lakes in the project impact area.

A visibility impact assessment is required under ARM 17.8.825 and ARM 17.8.1103, which states that the visibility requirements are applicable to the owner or operator of a proposed major stationary source, as defined by ARM 17.8.802(22). ARM 17.8.1106(1) requires that "the owner or operator of a major stationary source "…demonstrate that the actual emissions (including fugitive emissions) will not cause or contribute to adverse impact on visibility within any federal Class I area or the Department shall not issue a permit."

SME-HGS provided a visibility impact assessment as required under ARM 17.8.825 and ARM 17.8.1103 using the CALPUFF/CALPOST modeling system. CALPOST compares visibility impacts from the modeled source(s) to pre-existing visual range at the affected Class I areas and calculates a percent reduction in background extinction (%ΔB_{ext}). The results of SME-HGS's final visibility analysis are included in Table 7 and show six days in which the modeled %ΔB_{ext} values from SME were $\geq$ 5%. Cumulative impact modeling was performed for those days to determine the %ΔB_{ext} value from all the existing permitted PSD increment-consuming sources that could contribute to visibility reduction. The modeling showed four days with cumulative modeled %ΔB_{ext} value greater than 10%.

Table 7: SME Final Visibility Results (Refined Methodology)

Class I Area	Met Data Year	Max. ΔB_{ext} 24-hr Average	Number of Days %ΔB_{ext} $\geq$ 5.0%	Peak Cumulative %ΔB_{ext}
Bob Marshall Wilderness Area	1990	1.57	0	NA
	1992	6.90	1	14.45
	1996	9.92	2	19.21
Gates of the Mountains Wilderness Area	1990	5.62	1	5.63
	1992	4.32	0	NA
	1996	5.77	1	15.05
Glacier National Park	1992	3.92	0	NA
	1996	1.21	0	NA
Scapegoat Wilderness Area	1990	2.31	0	NA
	1992	4.30	0	NA
	1996	5.31	1	13.65
UL Bend Wilderness Area	1992	2.09	0	NA
	1996	4.47	0	NA

The Department reviewed the visibility analysis and determined that the SME-HGS project alone and the cumulative impact of all permitted PSD increment-consuming sources will not cause or contribute to an adverse impact on visibility. The proposed emissions will not result in visibility impairment which the Department determines does, or is likely to, interfere with the management, protection, preservation, or enjoyment of the visual experience of visitors within the affected federal Class I area. This determination takes into account the geographic extent, intensity, duration, frequency, and time of visibility impairment, and how these factors correlate with times of visitor use of the federal Class I area, and the frequency and occurrence of natural conditions that reduce visibility.

Conclusion

The preceding analysis represents a summary of predicted ambient air quality impacts resulting from the proposed SME-HGS project. A comprehensive and complete dispersion modeling analysis demonstrating compliance with all applicable increments and standards is on file with the

Department. Based on this analysis, the Department determined that the proposed project operating in compliance with the applicable requirements contained in Permit #3423-00 is expected to maintain compliance with all applicable increments and standards as required for permit issuance.

VII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, the Department conducted a private property taking and damaging assessment and determined there are no taking or damaging implications.

VIII. Environmental Assessment

The proposed SME-HGS project is subject to review under the requirements of the Montana Environmental Policy Act. A comprehensive draft environmental impact statement (EIS) is scheduled for issuance on June 30, 2006.

Permit Analysis Prepared By: M. Eric Merchant, MPH
Date: May 25, 2006

Commonwealth of Kentucky
Environmental and Public Protection Cabinet
Department for Environmental Protection
Division for Air Quality
803 Schenkel Lane
Frankfort, Kentucky 40601
(502) 573-3382

Final

AIR QUALITY PERMIT

Issued under 401 KAR 52:020

Permittee Name:	**Louisville Gas and Electric Company**
Mailing Address:	**P.O. Box 32010, Louisville, Kentucky, 40232**
Source Name:	**Louisville Gas and Electric Company**
Mailing Address:	**P.O. Box 32010, Louisville, Kentucky, 40232**
Source Location:	**487 Corn Creek Road, Bedford, Kentucky,**
Permit Number:	**V-02-043 Revision 2**
Source A. I. #:	**4054**
Activity #:	**APE20040003**
Review Type:	**Operating, PSD/TV**
Source ID #:	**21-223-00002**
ORIS Code:	**6071**
Regional Office:	**Florence Regional Office** **8020 Veterans Memorila Drive, Suite 110** **Florence, KY 41042** **(859) 525-4923**
County:	**Trimble**
Application Complete Date:	**February 11, 2005**
Issuance Date:	**June 20, 2003**
Revision Date:	**November 17, 2005** **January 4, 2006**
Expiration Date:	**June 20, 2008**

John S. Lyons, Director
Division for Air Quality

Revised 10/19/05

TABLE OF CONTENTS

Rev#	Permit type	Log #	Complete Date	Issuance Date	Summary of Action
----	Initial Issuance	F720	12-13-1996	NA	Was not issued proposed or final. Public notification was done.
1	Acid Rain Permit	F526	3-03-1998	3-05-1999	Permit for Unit 1-tangential coal fired boiler
2	PSD permit	53460	01-14-2001	06-22-2001	Permit issued for CT unit only without expiration
3	PSD/TV proposed permit	53460	12-19-02	06-06-03	Consolidating all permits into one
4	Permit Revision one	APE2004 0003	12-24-04	01-04-05	Emission limit as enforceable as practical matter (emission reduction) and the usage of two to three dry bulk trailers for fly ash transport
5	Significant Revision	APE2004 0004	2-11-05	1-4-06	Construction of new utility boiler, creditable emission reduction on source wide sulfur dioxide, and addition of NOx budget to the permit.

SECTION A - PERMIT AUTHORIZATION

Pursuant to a duly submitted application the Kentucky Division for Air Quality hereby authorizes the operation of the equipment described herein in accordance with the terms and conditions of this permit. This permit has been issued under the provisions of Kentucky Revised Statutes Chapter 224 and regulations promulgated pursuant thereto.

The permittee shall not construct, reconstruct, or modify any affected facilities without first having submitted a complete application and receiving a permit for the planned activity from the permitting authority, except as provided in this permit or in 401 KAR 52:020, Title V Permits.

Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits, licenses, or approvals required by this Cabinet or any other federal, state, or local agency.

SECTION B -EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

Emissions Unit: 01 (01) - Unit 1 Indirect Heat Exchanger

Description:
Construction commenced: on or before September 18, 1978
Pulverized coal-fired, dry bottom, tangentially fired, equipped with Selective Catalytic Reduction (SCR), electrostatic precipitator and wet spray scrubber with limestone/lime injection
Up to forty (40) percent petroleum coke co-firing with coal
Number two fuel oil used for startups and flame stabilization
Maximum continuous rating: 5,333 mmBtu/hour

Applicable Regulations:
401 KAR 51:017, Prevention of significant deterioration of air quality
401 KAR 51:160, NO_x requirements for large utility and industrial boilers; incorporating by reference 40 CFR 96
401 KAR 52:060, Acid rain permits, incorporating by reference the Federal Acid Rain provisions as codified in 40 CFR Parts 72 to 78
401 KAR 59:015, New Indirect Heat exchangers with more than 250 mmBtu per hour capacity and commenced on or after August 17, 1971;
40 CFR 60 Subpart D, Standards of Performance for fossil-fuel-fired steam generators, for an emissions unit greater than 250 mmBtu/hour and commenced after August 17, 1971;

1. **Operating Limitations:**
None

2. **Emission Limitations:**

a) Pursuant to 401 KAR 59:015, Section 4(1)(b), and 401 KAR 51:017, particulate emissions shall not exceed 0.1 lb/mmBtu based on a three-hour average.

The permittee may assure continuing compliance with the particulate emission standard by operating the affected facility and associated control equipment such that the opacity does not exceed the upper limit of the indicator range developed from continuous opacity monitoring (COM) data collected during stack tests. If five (5) percent of COM data (based on a three-hour rolling average) recorded in a calendar quarter show excursions from the indicator range, the permittee shall contact the Division within thirty (30) days after the end of the quarter to schedule a stack test to demonstrate compliance with the particulate standard while operating at the conditions which resulted in the excursions. The Division may waive this testing requirement upon a demonstration that the cause of the excursions has been corrected, or may require stack tests at any time pursuant to 401 KAR 50:045, Performance tests.

b) Pursuant to 401 KAR 59:015, Section 4(2), emissions shall not exceed twenty (20) percent opacity based on a six-minute average except a maximum of twenty-seven (27) percent opacity for not more than one (1) six (6) minute period in any sixty (60)

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

2. Emission Limitations continued:

consecutive minutes. Opacity shall be demonstrated by using EPA reference Method 9. Alternatively, the permittee may use COM in determining compliance with opacity.

c) Pursuant to 401 KAR 51:017, sulfur dioxide emissions shall not exceed 0.84 lb/mmBtu based on a three-hour rolling average.

d) Pursuant to 401 KAR 59:015, Section 6(1)(c), nitrogen oxides emissions expressed as nitrogen dioxide shall not exceed 0.7 lb/mmBtu based on a three-hour rolling average.

e) Pursuant to 401 KAR 51:001, Section 1, (146), source has accepted a voluntary limit such that consecutive twelve month rolling total of nitrogen oxide emissions shall not exceed 5,556 tons per year, which through this permit is enforceable as a practical matter. This limit commenced on January 1, 2005.

f) Pursuant to 40 CFR Part 76, nitrogen oxides emissions expressed as nitrogen dioxide shall not exceed 0.45 lb/mmBtu on an annual basis. See Section J, Acid Rain Permit.

g) Pursuant to 401 KAR 51:001, Section 1, (146), source has accepted a voluntary limit such that consecutive twelve month rolling total of sulfur dioxide emissions shall not exceed 4,822 tons per year, which through this permit is enforceable as a practical matter. This limit shall commence on January 1, 2006.

Compliance with nitrogen oxide and sulfur dioxide emissions:

Permittee shall monitor and calculate emissions on a consecutive twelve month rolling total as measured by the continuous emissions monitor (CEM) required pursuant to 40 CFR 75.2(a)

3. Testing Requirements:

a) The permittee shall submit a schedule within six months from the initial issuance date of this permit to conduct at least one performance test for particulate within one year following the issuance of this permit. The upper limit of the indicator range shall be developed from the COM data collected during the stack tests.

b) If no additional stack tests are performed pursuant to Condition 2. a) above, the permittee shall conduct one performance test for particulate emissions within the third year of the term of this permit to demonstrate compliance with the allowable standard.

c) The permittee shall determine the opacity of emissions from the stack by EPA Reference Method 9 annually, or more frequently if requested by the Division.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

4. Specific Monitoring Requirements:

a) Pursuant to 401 KAR 59:015, Section 7(1) and Section 7(4), 401 KAR 59:005, Section 4, continuous emission monitoring systems shall be installed, calibrated, maintained, and operated for measuring the opacity of emissions, sulfur dioxide, nitrogen oxides, and either oxygen or carbon dioxide emissions. The owner or operator shall ensure the continuous emission monitoring systems are in compliance with, and the owner or operator shall comply with the requirements of 401 KAR 59:005, Section 4.

b) Pursuant to 401 KAR 59:015, Section 7(3), for performance evaluations of the sulfur dioxide and nitrogen oxides continuous emission monitoring system as required under 401 KAR 59:005, Section 4(3) and calibration checks as required under 401 KAR 59:005, Section 4(4), reference methods 6 or 7 shall be used as applicable as described by 401 KAR 50:015.

c) Pursuant to 401 KAR 59:015, Section 7(3), sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B to 40 CFR 60, filed by reference in 401 KAR 50:015.

d) Pursuant to 401 KAR 59:015, Section 7(3), the span value for the continuous emission monitoring system measuring opacity of emissions shall be eighty (80), ninety (90), or one-hundred (100) percent and the span value for the continuous emission monitoring system measuring sulfur dioxide and nitrogen oxides emissions shall be in accordance with 401 KAR 59:015, Appendix C.

e) All span values computed under (d) above for burning combinations of fuels shall be rounded to the nearest 500 ppm.

f) Continuous emission monitoring data shall be converted into the units of applicable standards using the conversion procedure described in 401 KAR 59:015, Section 7(5).

g) Pursuant to 401 KAR 59:015, Section 7(3), for an indirect heat exchanger that simultaneously burns fossil fuel and non-fossil fuel, the span value of all continuous monitoring systems shall be subject to the Division's approval.

5. Specific Record Keeping Requirements:

a) Pursuant to 401 KAR 59:005, Section 3 (4), the owner or operator of the indirect heat exchanger shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems and devices; and all other information required by 401 KAR 59:005 recorded in a permanent form suitable for inspection.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b) Pursuant to 401 KAR 52:020, records, including those documenting the results of each compliance test, shall be maintained for five (5) years.

c) Pursuant to 401 KAR 59:005, Section 3(2), the owner or operator of this unit shall maintain the records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the emissions unit, any malfunction of the air pollution control equipment; or any period during which a continuous monitoring system or monitoring device is inoperative.

d) The permittee shall maintain records of the COM data on a three-hour rolling average basis, the number of excursions above the indicator range, time and date of excursions, opacity value of the excursions, and percentage of the COM data showing excursions from the indicator range in each calendar quarter.

6. <u>Specific Reporting Requirements:</u>

a) Pursuant to 401 KAR 59:005, Section 3 (3), minimum data requirements which follow shall be maintained and furnished in the format specified by the Division. Owners or operators of facilities required to install continuous monitoring systems shall submit for every calendar quarter a written report of excess emissions (as defined in applicable sections) to the Division. All quarterly reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter and shall include the following information:

1) The magnitude of the excess emission computed in accordance with the 401 KAR 59:005, Section 4(8), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

2) All hourly averages shall be reported for sulfur dioxide and nitrogen oxides monitors. The hourly averages shall be made available in the format specified by the Division.

3) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the emissions unit. The nature and cause of any malfunction (if known), the corrective action taken or preventive measures adopted.

4) The date and time identifying each period during which continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

5) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

b) Pursuant to 401 KAR 59:015, Section 7(7), for the purposes of reports required under 401 KAR 59:005, Section 3(3), periods of excess emissions are defined as follows:

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

6. Specific Reporting Requirements continued:

1) Excess emissions are defined as any six minute period during which the average opacity of emissions exceeds twenty percent opacity, except that one (1) six (6) minute average per hour of up to twenty-seven (27) percent opacity need not be reported.

2) Excess emissions of sulfur dioxide are defined as any three (3) hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable sulfur dioxide emissions standards.

3) Excess emissions for emissions units using a continuous monitoring system for measuring nitrogen oxides are defined as any three (3) hour period during which the average emissions (arithmetic average of three contiguous one hour periods) exceed the applicable nitrogen oxides emissions standards.

c) The permittee shall report the number of excursions above the indicator range, date and time of excursions, opacity value of the excursions, and percentage of the COM data showing excursions from the indicator range in each calendar quarter.

d) The permittee shall report quarterly the twelve-month rolling total sulfur dioxide and nitrogen oxides emissions.

7. Specific Control Equipment Operating Conditions:

a) The electrostatic precipitator and wet spray scrubber with limestone/lime injection shall be operated as necessary to maintain compliance with permitted emission limitations, in accordance with manufacturer's specifications and/or standard operating practices.

b) Records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

SECTION B -EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Units: 02 (02, 03, 04) - Auxiliary boilers A, B, and C

Description:
Constructed commenced on or before: December 28, 1987
#2 Fuel Oil-fired Units
Maximum continuous rating: 11.76 mmBtu/hour, each

Applicable Regulations:
401 KAR 59:015, New indirect heat exchangers, applicable to an emissions unit less than 250 mmBtu/hour and commenced on or after April 9, 1972.

1. Operating Limitations:
Total annual #2 fuel oil usage rate for all auxiliary boilers A, B, and C (emission point 02) shall not exceed 682,500 gallons per year and sulfur content shall not exceed 0.8 percent, to demonstrate non-applicability of Prevention of Significant Deterioration of Air Quality.

2. Emission Limitations:

a) Pursuant to 401 KAR 59:015, Section 4(1)(b), particulate emissions shall not exceed 0.1 lb/mmBtu based on a three-hour average. Compliance with the allowable particulate standard may be demonstrated by calculating particulate emissions using fuel heating value, and emission factor information (Particulate formula: (0.002 lbs/gallon) / heating value in mmBtu/gallon.)

b) Pursuant to 401 KAR 59:015, Section 4(2), emissions shall not exceed twenty (20) percent opacity based on a six-minute average except a maximum of forty (40) percent opacity for not more than six (6) consecutive minutes in any sixty (60) consecutive minutes during cleaning the firebox or blowing soot is allowed.

c) Pursuant to 401 KAR 59:015, Section 5(1)(b), the sulfur dioxide emission rate shall not exceed 0.8 lb/mmBtu based on a three-hour average. Compliance with the allowable sulfur dioxide standard shall be demonstrated by calculating sulfur dioxide emissions using fuel heating value, fuel supplier certification with sulfur content, and emission factor information (AP-42 factors below). Sulfur dioxide formula: (0.142 lb/gallon x Percent Sulfur in fuel) / heating value in mmBtu/gallon.

3. Testing Requirements:
Compliance with the opacity standard shall be demonstrated by reading the opacity once in every quarter by EPA Reference Method 9.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

4. Specific Monitoring Requirements:

a) To demonstrate continuing compliance with the fuel oil sulfur content limitation, monitoring of operations shall consist of, on an as-received basis, fuel supplier certification of the sulfur content of the fuel oil to be combusted. The fuel supplier certification shall include the name of the oil supplier, sulfur content, and a statement that the oil complies with the specifications under the definition for distillate oil in 401 KAR 60:005.

b) The fuel oil sulfur content and heating value shall be determined for the #2 fuel oil, as received, by fuel supplier certification.

5. Specific Record Keeping Requirements:

a) Pursuant to 401 KAR 59:005, Section 3 (4), the owner or operator of the indirect heat exchanger shall maintain a file of all measurements, including monthly #2 fuel oil usage. The owner or operator shall maintain a file of the fuel supplier certification; and all other information required by 401 KAR 59:005 recorded in a permanent form suitable for inspection. The file shall be retained for at least five (5) years following the date of such measurements, maintenance, reports, and records.

b) Records of the #2 fuel oil used shall be maintained.

6. Specific Reporting Requirements:

See Section F.

7. Specific Control Equipment Operating Conditions:

NA

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 05 (05, 06, -) - Fossil Fuel Handling Operations and Plant Roadways

Description:
Construction commenced on or before: 1990

Equipment includes:	Maximum Operating Rate (Tons/hour)
Continuous barge unloader, one barge unloader bin, and fossil fuel stacker reclaimer	5500
One active pile, one inactive pile, stackout conveyor S, one reclaim hopper	3000
Plant Roadways	NA

Applicable Regulations:
401 KAR 63:010, Fugitive emissions, and
401 KAR 51:017, Prevention of significant deterioration of air quality.

1. Operating Limitations:

a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not be limited to the following:

1. application and maintenance of asphalt, application of water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dusts;

2. operation of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling;

3. the maintenance of paved roadways in a clean condition;

4. the prompt removal of earth or other material from a paved street which earth or other material has been transported thereto by trucking or other earth moving equipment or erosion by water.

b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

e) No one shall allow earth or other material being transported by truck or earth moving equipment to be deposited onto a paved street or roadway, pursuant to 401 KAR 63:010, Section 4.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

2. Emission Limitations:
None

3. Testing Requirements:
None

4. Specific Monitoring Requirements:

See Section F.

5. Specific Record Keeping Requirements:

a) Records of the fossil fuels received and processed shall be maintained for emissions inventory purposes.

b) Annual records estimating the tonnage hauled for plant roadways shall be maintained for emissions inventory purposes.

6. Specific Reporting Requirements:
See Section F.

7. Specific Control Equipment Operating Conditions:

a) The surfactants, enclosures, and a rotoclone for the fossil fuel receiving operations and the dust water suppressant system for the stockpile operations shall be used as necessary to maintain compliance with applicable requirements, in accordance with manufacturer's specifications and/or standard operating practices.

b) Plant roadways shall be controlled with water as necessary to comply with 401 KAR 63:010.

c) Records regarding the maintenance and use of the surfactants, enclosures, and a rotoclone for the fossil fuel receiving operations and the dust water suppressant system for the stockpile operations shall be maintained.

d) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 07 (07, 08, 09) - Fossil Fuel Handling Operations (Please refer to Units 36, 37, 38, and 39 for additional future fossil fuel handling operation information)

Description:

Construction commenced on or before: 1990

Continuous Barge Unloader –

One Barge Unloader Bin

Conveyor System -

Conveyor Belt A:	From Continuous Barge Unloader to Conveyor B
Conveyor Belt B:	From Conveyor A to Transfer House/Conveyor C
Conveyor Belt C:	From Transfer House to Coal Sample House Bin
Conveyor Belt D:	From Coal Sample House Bin to Conveyor E1 or S
Conveyor Belt E1:	From Conveyor D to Active Storage and Crusher House
Conveyor Belts F1 & F2:	From Crusher House to Conveyors G1 & G2
Conveyor Belts G1 & G2:	From Conveyors F1 & F2 to Unit 1 & 2 Coal Silos
Conveyor Belt S:	From Conveyor D to One Inactive Fossil Fuel Pile
Reclaim Hopper & Conveyor Belt R1:	From One Inactive Fossil Fuel Pile to Crusher House

Crusher House -

Two crushers, fossil fuel crusher bin, and fuel blender: Crusher House Activities

Operating Rate–

Continuous Barge Unloader	Transfer Rates
One Barge Unloader	5,500 tons/hour

Conveyor System -

Conveyor Belt A:	5,500 tons/hour
Conveyor Belt B:	5,500 tons/hour
Conveyor Belt C:	5,500 tons/hour
Conveyor Belt D:	3,000 tons/hour
Conveyor Belt E1:	2,640 tons/hour
Conveyor Belts F1 & F2:	1,320 tons/hour
Conveyors G1 & G2	1,320 tons/hour
Conveyor Belt S:	1,650 tons/hour
Reclaim Hopper & Conveyor Belt R1:	1,320 tons/hour

Crusher House -

Two crushers, fossil fuel crusher bin, and fuel blender: 3,600 tons/hour

Power House -

Six Unit 1 fossil fuel silos: 800 tons/hour

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Applicable Regulations:
401 KAR 60:005, incorporating by reference 40 CFR 60 Subpart Y, Standards of Performance for Coal Preparation Plants for units commenced after October 24, 1974
401 KAR 51:017, Prevention of significant deterioration of air quality

1. Operating Limitations:
None

2. Emission Limitations:
Pursuant to 401 KAR 60:005 incorporating by reference 40 CFR 60.252, the owner or operator subject to the provisions of this regulation shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.

3. Testing Requirements:
Pursuant to 401 KAR 60:005 incorporating by reference, 40 CFR 60.254, EPA Reference Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity at least annually, or more frequently if requested by the Division.

4. Specific Monitoring Requirements:
The permittee shall perform a qualitative visual observation of the opacity of emissions from each stack on a weekly basis and maintain a log of the observations. If visible emissions from any stack are seen, the permittee shall determine the opacity of emissions by Reference Method 9 and instigate an inspection of the control equipment making any necessary repairs.

5. Specific Record Keeping Requirements:
Records of the fossil fuels processed shall be maintained for emissions inventory purposes.

6. Specific Reporting Requirements:
See Section F.

7. Specific Control Equipment Operating Conditions:

a) The enclosures, surfactants, and rotoclone(s) for crushing and associated conveying operations, the partial enclosures for conveyor system with belts A, B, C, D, G1, G2, 1, 2, and fuel blender, and baghouse for the six fossil fuel silos shall be used/operated as necessary to maintain compliance with permitted emission limitations, in accordance with manufacturer's specifications and/or standard operating practices.

b) Records regarding the maintenance and use/operation of the control equipment listed in 7(a) shall be maintained.

c) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 10 (10 and 11) - Lime/Limestone Handling and Processing

Description:

Equipment includes: Receiving Operations: clamshell unloader, clamshell barge unloader bin;
Stockpile/Stackout Operations: active pile, inactive pile
Construction commenced on or before: 1990
Maximum Operating Rate (Receiving): 1650 Tons/hour
Maximum Operating Rate (Stockpile/Stackout): 1500 Tons/hr

Applicable Regulations:
401 KAR 63:010, Fugitive emissions
401 KAR 51:017, Prevention of significant deterioration of air quality

1. **Operating Limitations:**
   a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not be limited to the following:

      1. application and maintenance of asphalt, application of water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dusts;

      2. operation of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling.

   b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

2. **Emission Limitations:**
   None

3. **Testing Requirements:**
   None

4. **Specific Monitoring Requirements:**
   See Section F.

5. **Specific Record Keeping Requirements:**
   Records of the lime and/or limestone received and processed shall be maintained for emissions inventory purposes.

6. **Specific Reporting Requirements:**
   See Section F.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

7. Specific Control Equipment Operating Conditions:

a) The wet spray low water surfactant and enclosures shall be used as necessary to maintain compliance with applicable requirements, in accordance with manufacturer's specifications and/or standard operating practices.

b) Records regarding the maintenance and use of the wet spray low water surfactant and enclosures shall be maintained.

c) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Units: 12 (12, 13) - Lime/Limestone Handling and Processing

Description:
Equipment Includes: underground crushing operation (one crusher);
and milling operations (two ball mills)
Construction commenced on or before: 1990
Operating Rate: 260 Tons/hour, each

Applicable Regulations:
401 KAR 60.670, New nonmetallic mineral processing plants, incorporating by reference 40 CFR 60, Subpart OOO, applies to each of the emissions units listed above, commenced after August 31, 1983
401 KAR 51:017, Prevention of significant deterioration of air quality

1. Operating Limitations:
None

2. Emission Standards:

a) Pursuant to 401 KAR 60.670, incorporating by reference 40 CFR 60.672(e), no owner or operator shall cause to be discharged into the atmosphere from any building enclosing any transfer point on a conveyor belt or any other emissions unit any visible fugitive emissions.

Note that the crusher building is located underground with no direct vent to the atmosphere; therefore as long as this is the case it is assumed to be in compliance.

3. Testing Requirements:
In determining compliance with 401 KAR 60.670, incorporating by reference 40 CFR 60.672(e) for fugitive emissions from buildings, the owner(s) or operator(s) shall determine fugitive emissions while all emissions units are operating in accordance with EPA Reference Method 22, annually.

4. Specific Monitoring Requirements:
The permittee shall inspect the control equipment weekly and make repairs as necessary to assure compliance.

5. Specific Record Keeping Requirements:
Records of the lime and/or limestone processed shall be maintained for emissions inventory purposes.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

6. <u>Specific Reporting Requirements:</u>

a) Pursuant to 401 KAR 60.670, incorporating by reference 40 CFR 60.676, the owner(s) or operator(s) of any emissions unit shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards of 40 CFR 60.672 and 401 KAR 59:310, including reports of observations using Method 22 to demonstrate compliance.

b) See Section F.

7. <u>Specific Control Equipment Operating Conditions:</u>

a) The enclosure shall be used as necessary to maintain compliance with permitted emission limitations, in accordance with manufacturer’s specifications and/or standard operating practices.

b) Records regarding the maintenance of the enclosure shall be maintained.

c) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 14 (14) - Lime/Limestone Handling and Processing

Description:
Equipment Includes: conveyors and transfer points (conveyor system, belts A, B, C, transfer bin, and reclaim hopper)
Construction commenced on or before: 1990
Maximum Operating Rate: 1500 Tons/hour, each

Applicable Regulations:
401 KAR 60:670, incorporating by reference 40 CFR 60 Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants, as modified by Section 3 of 401 KAR 60:670, applies to each of the emissions units listed above, commenced after August 31, 1983
401 KAR 51:017, Prevention of significant deterioration of air quality

1. Operating Limitations:
None

2. Emission Standards:

a) Pursuant to 401 KAR 60.670, incorporating by reference 40 CFR 60.672 (b), the owner(s) or operator(s) shall not cause to be discharged into the atmosphere from any transfer point on belt conveyors or from any other emissions unit any fugitive emissions which exhibit greater than ten (10) percent opacity.

b) Pursuant to 401 KAR 60.670, incorporating by reference 40 CFR 60.672(e), no owner or operator shall cause to be discharged into the atmosphere from any building/enclosure enclosing any transfer point on a conveyor belt or any other emissions unit any visible fugitive emissions.

3. Testing Requirements:

a) EPA Reference Method 9 and the procedures in 40 CFR 60.11 and 40 CFR 60.675 shall be used for determining opacity, annually.

b) In determining compliance with 401 KAR 401 KAR 60.670, incorporating by reference 40 CFR 60.672(e) for fugitive emissions from buildings/enclosures, the owner(s) or operator(s) shall determine fugitive emissions while all emissions units are operating in accordance with EPA Reference Method 22, annually.

4. Specific Monitoring Requirements:
The permittee shall inspect the control equipment weekly and make repairs as necessary to assure compliance.

5. Specific Record Keeping Requirements:
Records of the lime and/or limestone processed shall be maintained for emissions inventory purposes.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

6. Specific Reporting Requirements:

a) Pursuant to 401 KAR 60.670, incorporating by reference 40 CFR 60.676, the owner(s) or operator(s) of any emissions unit shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards of 40 CFR 60.672, including reports of opacity observations made using Method 9 to demonstrate compliance, and reports of observations using Method 22 to demonstrate compliance.

b) See Section F.

7. Specific Control Equipment Operating Conditions:

a) The partial enclosures shall be used as necessary to maintain compliance with permitted emission limitations, in accordance with manufacturer's specifications and/or standard operating practices.

b) Records regarding the maintenance of the partial enclosures shall be maintained.

c) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 18 (18) - Emergency Diesel Generator

Description:
Maximum Output: 150 kW
Rated capacity: 16.1 gallons/hour diesel fuel
Constructed on or before date: 1995

Applicable Regulations:
None

1. Operating Limitations:
None

2. Emission Limitations:
None

3. Testing Requirements:
None

4. Specific Monitoring Requirements:
See Section F.

5. Specific Record Keeping Requirements:
Records of the fuel usage rate shall be maintained for emissions inventory purposes.

6. Specific Reporting Requirements:
See Section F.

7. Specific Control Equipment Operating Conditions:
NA

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 20 (17) - Existing Natural Draft Cooling Tower (with five chemical injection pumps and two circulating water pumps)

Description:

Control Equipment:	0.008% Drift Eliminators
Circulating Water Rate:	238,227 Gallons per Minute
Construction Commenced Date:	September 1990

Applicable Regulations:

401 KAR 63:010, Fugitive emissions

401 KAR 51:017, Prevention of Significant Deterioration of Air Quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:

a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.

b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

2. Emission Limitations:

a) Pursuant to 401 KAR 51:017, the cooling tower shall utilize 0.008% Drift Eliminators.

b) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.

3. Testing Requirements:

None

4. Specific Monitoring Requirements:

The permittee shall monitor of total dissolved solids content of the circulating water on a monthly basis.

5. Specific Record Keeping Requirements:

a) The owner or operator shall maintain records of the manufacturer's design of the Drift Eliminators.

b) The owner or operator shall maintain records of water circulation rate and monthly records of the circulating water total dissolved solids content.

6. Specific Reporting Requirements:

See Section F for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

7. Specific Control Equipment Operating Conditions:

a) Pursuant to 401 KAR 50:055, Section 5, the drift eliminators shall be maintained and operated to ensure the emission units are in compliance with applicable requirements of 401 KAR 63:010 and in accordance with manufacturer's specifications and/or standard operating practices.

b) See Section E for further requirements.

SECTION B -EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Units: 25 – 30 (Emission Points 25 -30) - 6 Combustion Turbines (TC5 - TC10)

Description:
1763 mmBtu/hr maximum rated heat input capacity (@ -10 degrees F), each, 160 MW nominal rated capacity output each. General Electric 7FA natural gas-fired simple cycle combustion turbines equipped with dry low NO_x burners.
Units 25 & 26 (TC 5 & TC6) are proposed to be installed in April of 2002
Units 27 & 28 (TC 7 & TC8) are proposed to be installed in February of 2004
Units 29 & 30 (TC 9 & TC10) are proposed to be installed in April of 2004

The following requirements are applicable to each combustion turbine

Applicable Regulations:
401 KAR 60:005, incorporating by reference 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, for emissions unit with a heat input at peak load equal to or greater than 10 mmBtu/hour for which construction commenced after October 3, 1977, and 40 CFR 60, Subpart A, General Provisions.
401 KAR 51:017, Prevention of significant deterioration of air quality
401 KAR 63:020, Potentially hazardous matter or toxic substances

1. Operating Limitations:

a) The Permittee shall not operate any combustion turbine below load levels at which performance testing has proven compliance with emission limitations, except during periods of startup and shutdown. Startup and shutdown periods shall be limited to no more than two hours for each startup/shutdown event.

b) The Permittee shall use only natural gas in the turbines.

2. Emission Limitations:

a) Pursuant to 401 KAR 51:017, nitrogen oxides emission levels in the exhaust gas shall not exceed a hourly average of 12 ppm by volume at 15 percent oxygen on a dry basis, and an annual (12 month rolling) average of 9 ppm by volume at 15 percent oxygen on a dry basis, except during periods of startup, shutdown, or malfunction. Continuous compliance with this limit shall be demonstrated by a continuous emission monitor (CEM). Compliance with this limit constitutes compliance with the nitrogen oxide limit contained in 40 CFR 60 Subpart GG.

b) Pursuant to 401 KAR 51:017, the fuel sulfur content due to the firing of natural gas shall not exceed 2.0 grains/100 SCF. Compliance with this limit shall be demonstrated by fuel sampling or vendor guarantees.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c) Pursuant to 401 KAR 51:017, except during periods of startup, shutdown, or malfunction, the carbon monoxide emission level in the exhaust gas shall not exceed 9 ppm by volume at 15 % oxygen, on a dry basis, during any 3-hour average period. Continuous compliance with this limit shall be demonstrated by a continuous emission monitor (CEM).

d) Pursuant to 401 KAR 51:017, particulate emissions shall not exceed 19 pounds per hour.

e) The permittee shall not allow total formaldehyde emissions in the exhaust gas to exceed 10 tons during any consecutive 12- month period.

f) See Section D.

3. <u>Testing Requirements</u>:

a) Pursuant to 40 CFR 60.335(b), in conducting performance tests required by 40 CFR 60.8, the owner or operator shall use as test methods and procedures the test methods in Appendix A of Part 60 or other methods or procedures as specified in 40 CFR 60.335, except as provided for in 40 CFR 60.8(b).

b) Pursuant to 401 KAR 50:045, the owner or operator shall conduct an initial performance test on at least one of the turbines for sulfur dioxide, nitrogen oxides, carbon monoxide, particulate matter and formaldehyde, with use of a reference test method approved by the Division.

c) See General Conditions G(d)(5) and G(d)(6).

4. <u>Specific Monitoring Requirements:</u>

a) Pursuant to 401 KAR 52:020, Section 10, and 40 CFR 75.2, the permittee shall install, calibrate, maintain, and operate the nitrogen oxides Continuous Emissions Monitor (CEM). The nitrogen oxides CEM shall be used as the indicator of continuous compliance with the nitrogen oxides emission standard. Excluding the startup and shut down periods, if any (1) one-hour average exceeds the nitrogen oxides emission limitation, the permittee shall, as appropriate, initiate an investigation of the cause of the exceedance and complete necessary control device/process/CEM repairs or take corrective action as soon as practicable.

b) Pursuant to 401 KAR 52:020, Section 10, the permittee shall monitor the quantity of natural gas, in millions of cubic feet, fired in each combustion turbine on a daily basis.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c) Pursuant to 40 CFR 60.334(b), the owner or operator of any stationary turbine shall monitor sulfur content of the fuel being fired in the turbine. The frequency of determination of these values shall be as specified in the following approved Custom fuel monitoring schedule. The permittee will sample the natural gas for sulfur content every six months or use vendor guarantees that the gas contains 2.0 grains/100 SCF of sulfur or less as proof of natural gas quality.

d) Pursuant to 401 KAR 52:020, Section 10, to meet the periodic monitoring requirement for carbon monoxide the permittee shall use a continuous emission monitor (CEM). Excluding the startup and shut down periods, if any (3) three-hour average carbon monoxide value exceeds the standard, the permittee shall, as appropriate, initiate an investigation of the cause of the exceedance and complete necessary process or CEM repairs or take corrective action as soon as practicable.

e) The permittee shall install, calibrate, operate, test, and monitor all continuous monitoring systems and monitoring devices in accordance with 40 CFR 60.13 or 40 CFR 75.10

f) The Permittee shall monitor the hours of operation of each combustion turbine on a daily basis.

g) The Permittee shall monitor the power output, in MW, of each combustion turbine on a daily basis.

5. **<u>Specific Record Keeping Requirements</u>:**

a) Pursuant to 40 CFR 60.7 (f), the owner or operator of the gas turbines shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems and devices; and all other information required by 40 CFR 60, Subpart A recorded in a permanent form suitable for inspection.

b) Records, including those documenting the results of each compliance test and all other records and reports required by this permit, shall be maintained for five (5) years pursuant to 401 KAR 52:020.

SECTION B -EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c) The permittee shall maintain a log of all sulfur content measurements as required in the approved custom fuel sulfur-monitoring plan (Condition 4(c) above).

d) The permittee shall maintain a daily log of the natural gas, in millions of cubic feet, fired in each combustion turbine, for any consecutive twelve (12) month period.

e) The permittee shall maintain a daily log of all hours of operation for each combustion turbine, for any consecutive twelve (12) month period.

f) The permittee shall maintain a daily log of all power output, in MW, for each combustion turbine, for any consecutive twelve (12) month period.

6. **Specific Reporting Requirements:**

a) Pursuant to 40 CFR 60.7 (c), minimum data requirements which follow shall be maintained and furnished in the format specified by the Division. Owners or operators of facilities required to install continuous monitoring systems shall submit for every calendar quarter a written report of excess emissions (as defined in applicable sections) to the Division. All quarterly reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter and shall include the following information:

1) The magnitude of the excess emissions computed in accordance with the 40 CFR 60.13 (h), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the emissions unit. The nature and cause of any malfunction (if known), the corrective action taken or preventive measures adopted.

3) The date and time identifying each period during which continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b) Pursuant to 401 KAR 52:020 Section 10, monitoring requirement with CEM for nitrogen oxides, excess emissions are defined as any (1) one-hour period during which the average emissions (arithmetic average) exceed the applicable nitrogen oxides emission standard. These periods of excess emissions shall be reported quarterly. The nitrogen oxide CEM reports will be used in lieu of the water to fuel ratio requirements of 40 CFR 60.334(c).

c) Pursuant to 40 CFR 60.334(c), excess emissions of sulfur dioxide are defined as any daily period (or as otherwise required in an approved custom fuel sulfur monitoring plan) during which the sulfur content of the fuel being fired in the gas turbine(s) exceeds the limitations set forth in Subsection 2, Emission Limitations. These periods of excess emissions shall be reported quarterly.

d) Pursuant to 401 KAR 52:020, Section 10, monitoring requirement with CEM for carbon monoxide, excess emissions are defined as any (3) three-hour period during which the average emissions (arithmetic average) exceed the applicable carbon monoxide emission standard. These periods of excess emissions shall be reported quarterly.

7. <u>Specific Control Equipment Operating Conditions</u>:

a) The Dry Low-NO_x Burners shall be operated to maintain compliance with permitted emission limitations, in accordance with manufacturer’s specifications and/or standard operating practices.

b) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 31 - Unit 2 - Supercritical Pulverized Coal Fired Steam Electric Generating Unit Nominal rating 750 MW

Description:
Supercritical Pulverized Coal (SPC) Boiler, equipped with Selective Catalytic Reduction (SCR); Pulse Jet Fabric Filter (PJFF); Wet Flue Gas Desulfurization (WFGD); and Wet Electrostatic Precipitator (WESP).
ASTM Grade No. 2-D S15 fuel oil used for startup and stabilization.
Design capacity rating: 6,942 mmBtu/hour
Fuels include (i) Eastern bituminous coal, and (ii) a blend of Western sub bituminous coal and Eastern bituminous coal.
Construction Commence Date: Estimated 2006

Applicable Regulations:
401 KAR 51:017, Prevention of Significant Deterioration of Air Quality applicable to major construction or modification commenced after September 22, 1982;
401 KAR 51:160, NO_x requirements for large utility and industrial boilers; incorporating by reference 40 CFR 96;
401 KAR 52:060, Acid rain permits, incorporating by reference the Federal Acid Rain provisions as codified in 40 CFR Parts 72 to 78;
401 KAR 59:016, New Electric Utility Steam Generating Units;
40 CFR 60, Appendix F, Quality Assurance Procedures
401 KAR 60:005, incorporating by reference 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units applicable to an emission unit with a capacity of more than 250 mmBtu per hour and commenced construction on or after September 19, 1978;
401 KAR 63:020, Potentially Hazardous Matter or Toxic Substances
40 CFR 64, Compliance Assurance Monitoring
40 CFR 75, Continuous Emission Monitoring
Compliance with 40 CFR 75, Continuous Emissions Monitoring, shall constitute compliance with the monitoring and quality assurance requirements of 401 KAR 59:016 and 40 CFR 60, Appendix F.

1. Operating Limitations:

The owner or operator shall install control devices selected as BACT.

- BACT for PM/PM_{10} is PJFF.
- BACT for CO is good combustion controls.
- BACT for H_2SO_4 mist is WESP.
- BACT for fluorides (as HF) is WFGD.
- BACT does not apply to NO_x and SO_2, however BACT type controls with similar emission levels will be installed with a SCR for NO_x emissions and WFGD for SO_2.
- Only ASTM Grade No.2-DS15, with a sulfur content not to exceed 15 ppm shall be used for startup and stabilization.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

2. Emission Limitations:

a) Pursuant to 401 KAR 59:016, Section 3(1)(b), and 401 KAR 51:017, particulate and PM_{10} emissions shall not exceed 0.018 lb/mmBtu (filterable and condensable) of heat input based on the average of three one-hour tests. Pursuant to 401 KAR 59:016, Section 6(1), compliance with the 0.018lb/mmBtu (filterable and condensable) emission limitation shall constitute compliance with the 99% reduction requirement contained in 401 KAR 59:016, Section 3(1)(b).

b) Pursuant to 401 KAR 60:005, Section 3(1)(c) and 40 CFR 60.42a(c), [per proposed revisions to NSPS Subpart Da published in the Federal Register on February 28, 2005] filterable particulate emissions shall not exceed 0.015 lb/mmBtu of heat input based on a three-hour rolling average.

c) Pursuant to 401 KAR 59:016, Section 3(2), emissions shall not exceed twenty (20) percent opacity based on a six-minute average except that a maximum of twenty-seven (27) percent is allowed for not more than one (1) six (6) minute period per hour.

d) Pursuant to 401 KAR 51:017, Sulfur dioxide emissions shall not exceed 8.94 tons per calendar day and 3,263.1 tons per 12 consecutive months total.

e) Pursuant to 401 KAR 60:005, Section 3(1)(c) and 40 CFR 60.43a(i), [per proposed revisions to NSPS Subpart Da published in the Federal Register on February 28, 2005], sulfur dioxide emissions shall not exceed 2.0 lb/MWh gross energy output, based on a thirty (30) day rolling average. Pursuant to 401 KAR 59:016, Section 4, compliance with this limit shall constitute compliance with the 70% reduction requirement contained in 401 KAR 59:016, Section 4(1)(b).

f) Pursuant to 401 KAR 51:017, Carbon monoxide emissions shall not exceed 0.10 lbs/mmBtu based on a thirty day rolling average or 0.5 lbs/mmBtu on a three hour rolling average.

g) Pursuant to 401 KAR 51:017, Nitrogen oxides emissions shall not exceed 4.17 tons per calendar day and 1,506.72 tons per 12 consecutive months total.

h) Pursuant to 401 KAR 60:005, Section 3(1)(c) and 40 CFR 60.44a(e), [per proposed revisions to NSPS Subpart Da published in the Federal Register on February 28, 2005], nitrogen oxides emissions shall not exceed 1.0 lb/MWh gross energy output, based on a 30-day rolling average. Pursuant to 401 KAR 59:016, Section 5, compliance with this limitation shall constitute compliance with the 65% reduction requirement contained in 401 KAR 59:016, Section 5(2)(e).

i) Pursuant to 401 KAR 51:017, VOC emissions shall not exceed 0.0032 lbs/mmBtu based on a three (3) hour rolling average. Compliance with this limit shall be demonstrated by compliance with Subsection 2(f) above.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

j) Pursuant to 401 KAR 51:017, Sulfuric acid mist emissions shall not exceed 26.6 lbs/hr based on a three (3) hour rolling average.

k) Pursuant to 401 KAR 51:017, Fluorides emissions shall not exceed 1.55 lbs/hr based on a three (3) hour rolling average.

l) Mercury emissions shall not exceed 13 x 10^{-6} lbs/MWh (Gross output) based on a consecutive twelve (12) month rolling average. Compliance with this limit ensures compliance with 40 CFR 60.45a.

m) Lead emissions shall not exceed 0.55 tons per year based on a 12-month rolling total.

n) Pursuant to 401 KAR 63:020, the use of good combustion controls, PJFF, WFGD, and WESP shall be used for the control of organic toxic substances.

o) Compliance with emission limits in Subsections (a), (d), (f) and (i) shall constitute compliance with 401 KAR 63:020 with respect to toxic substances. Mercury is not regulated under 401 KAR 63:020 pursuant to 401 KAR 63:020 Section 1.

p) The above emission limitations shall not apply during periods of startup and shutdown. However, emissions during startup and shutdown shall be included in determining compliance with tons per year limits specified in this permit. Pursuant to 401 KAR 51:017, the owner or operator shall utilize good work and maintenance practices and manufacturer's recommendations to minimize emissions during, and the frequency and duration of, such events.

3. <u>Testing Requirements:</u>

a) Pursuant to 401 KAR 50:055, Section 2(1)(a) the owner or operator shall demonstrate compliance with the applicable emission standards within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the unit.

b) Pursuant to 401 KAR 50:045, Section 2 and 50:015, Section 1, the owner or operator shall determine the opacity of emissions from the stack by EPA Reference Method 9 as requested by the Division.

c) See Section D for further requirements.

4. <u>Specific Monitoring Requirements:</u>

a) Pursuant to 401 KAR 52:020, 401 KAR 59:016, Section 7, 401 KAR 51:017, 401 KAR 60:005, Section 3(1)(c), and 401 KAR 59:005, Section 4, the owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, carbon monoxide emissions, nitrogen oxides emissions, particulate matter emissions, mercury

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

emissions, and either oxygen or carbon dioxide diluents. Oxygen or carbon dioxide shall be monitored at each location where sulfur dioxide or nitrogen oxides emissions are monitored. The owner or operator shall ensure the continuous monitoring systems are in compliance with the requirements of 401 KAR 59:005, Section 4. Due to the wet nature of the stack, a continuous opacity monitor (COM) shall be located after the PJFF and before the WFGD as an indicator of performance.

b) Pursuant to 401 KAR 52:020, 401 KAR 59:016, Section 7(2) and 40 CFR 75.2, to meet the continuous monitoring requirement for sulfur dioxide, the owner or operator shall use a continuous emission monitor (CEM). If any 30 day rolling average (excluding the startup and shut down periods) or 8.94 tons per day limit for sulfur dioxide exceeds the limits, the owner or operator shall, as appropriate, initiate an inspection of the control equipment and/or the CEM system and make any necessary repairs as soon as practicable.

c) Pursuant to 401 KAR 52:020, 401 KAR 59:016, Section 7(3) and 40 CFR 75.2, to meet the continuous monitoring requirement for nitrogen oxide, the owner or operator shall use a CEM. If any 30 day rolling average (excluding the startup and shut down periods) or 4.17 tons per day limit for nitrogen oxide exceeds the limits, the owner or operator shall, as appropriate, initiate an inspection of the control equipment and/or the CEM system and make any necessary repairs as soon as practicable.

d) Pursuant to 401 KAR 52:020, Section 10 and 401 KAR 51:017, to meet the periodic monitoring requirement for CO, the owner or operator shall use a CEM.

e) Pursuant to 401 KAR 52:020, Section 10 and 401 KAR 51:017, to meet the periodic monitoring requirement for PM/PM_{10}, the owner or operator shall use a CEM.

f) Pursuant to 401 KAR 52:020, Section 10 and 40 CFR 60.49a(p), to meet the periodic monitoring requirement for mercury the owner or operator shall use a CEM.

g) Pursuant to 40 CFR 60.49a, 401 KAR 52:020 and 401 KAR 59:016, Section 7(5), all the CEM systems shall be operated and data shall be recorded during all periods of operation of the emissions units including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

h) Pursuant to 401 KAR 52:020 and 401 KAR 59:016, Section 7(6), when emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, the owner or operator shall obtain emission data by using other monitoring systems as approved by the Division or the reference methods as described in 401 KAR 59:016, Section 7(8) or other data substitution methods, including 40 CFR 75, to provide emission data for a minimum of eighteen hours in at least twenty-two out of thirty successive boiler operating days.

i) Pursuant to 401 KAR 59:016, Section 7(9), the following procedures shall be used to conduct monitoring system performance evaluations and calibration checks as required under 401 KAR 59:005, Section 4(3):

1. Reference Method 6 or 7, as applicable shall be used for conducting performance evaluations of sulfur dioxide and nitrogen oxides CEM systems.

2. Sulfur dioxide or nitrogen oxides, as applicable, shall be used for preparing calibration mixtures under Performance Specification 2 of Appendix B to 40 CFR 60 incorporated by reference in 401 KAR 50:015, or under 40 CFR 75.

3. The span value for the continuous monitoring system for measuring opacity shall be between sixty (60) and eighty (80) percent and the span value for the continuous monitoring system for measuring nitrogen oxides shall be 1,000 ppm, or span values as specified in 40 CFR 75, Appendix A.

4. The span value for the continuous monitoring system for measuring sulfur dioxide at the outlet of the control device shall be 50 percent of the maximum estimated hourly potential emissions of the fuel fired, or span values as specified in 40 CFR 75, Appendix A.

j) CAM Requirements. The owner or operator shall use Sulfur Dioxide (SO_2), Nitrogen Oxides (NO_x), and particulate matter (PM/PM_{10}) Continuous Emissions Monitors (CEMs) as continuous compliance determination methods consistent with 40 CFR 64.4(d) for those specific parameters, and to demonstrate compliance with Best Available Control Technology (BACT) limits contained in this permit, as applicable.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Pursuant to 40 CFR 64.6, monitoring for H_2SO_4 and Fluoride is shown in the table below:

TABLE 1: CAM MONITORING APPROACH

Applicable CAM Requirement	H_2SO_4 Mist	Fluoride
General Requirements	26.6 lb/hr 3 hour rolling average	1.55 lb/hr 3 hour rolling average
Monitoring Methods and Location	SO_2 CEMs plus initial source test, WESP liquid flow rate, voltage, secondary currents and/or operating parameters, in conjunction with initial performance tests to establish excursion and exceedance, shall be monitored	SO_2 CEMs plus initial source test, weekly coal sampling (as received) with quarterly coal composites
Indicator Range	Initial source testing to establish correlation to SO_2 and coal quality, then establish SO_2 CEM and coal range appropriate	Initial source testing to establish correlation to SO_2 and coal quality, then establish SO_2 CEM and coal range appropriate
Data Collection Frequency	Continuous SO_2 CEM, weekly coal sampling (as received) with quarterly coal composites	Continuous SO_2 CEM, weekly coal sampling (as received) with quarterly coal composites
Averaging Period	3 hour rolling	3 hour rolling
Recordkeeping	Coal quality information will be kept in a designated hard copy or electronic archive, plus CEM data system records	Coal quality information will be kept in a designated hard copy or electronic archive, plus CEM data system records
QA/QC	WFGD/WESP will be maintained and operated in accordance with manufacturer specifications and recommendations	WFGD/WESP will be maintained and operated in accordance with manufacturer specifications and recommendations

5. Specific Record Keeping Requirements:

a) Pursuant to 401 KAR 59:005, Section 3(4), the owner or operator of this unit shall maintain a record of applicable measurements, including CEM system, monitoring device, and performance testing measurements; all CEM system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems and devices; and all other information required by 401 KAR 59:005 recorded in a permanent form suitable for inspection.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b) Pursuant to 401 KAR 59:005, Section 3(2), the owner or operator of this unit shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility, any malfunction of the air pollution control equipment; or any period during which a CEM system or emission monitoring device is inoperative.

c) Pursuant to KAR 52:020, Section 10 and 401 KAR 50:045, Section 6, the owner or operator shall maintain the results of all compliance tests.

d) CAM Requirements

1. Pursuant to 40 CFR 64.9(b), the owner or operator shall record on a daily basis for the WFGD the following:

   a. The WFGD liquid pH in the reaction tank;
   b. Recycle pump amps and status.

2. Pursuant to 40 CFR 64.9(b), the owner or operator shall record, on a daily basis, voltages, or other parameters identified during the performance test for the WESP, as approved by the Division.

6. **Specific Reporting Requirements:**

a) Pursuant to 401 KAR 59:005, Section 3(3), minimum data requirements which follow shall be maintained and furnished in the format specified by the Division. Owners or operators of facilities required to install continuous monitoring systems shall submit for every calendar quarter a written report of excess emissions (as defined in applicable sections) to the Division. All quarterly reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter and shall include the following information:

1. The magnitude of the excess emission computed in accordance with the 401 KAR 59:005, Section 4(8), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

2. All hourly averages shall be reported for sulfur dioxide and nitrogen oxides monitors. The hourly averages shall be made available in the format specified by the Division.

3. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The permittee shall determine the nature and cause of any malfunction (if known), and initiate the corrective action taken or preventive measures adopted.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

4. The date and time identifying each period during which continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

5. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

6. For sulfur dioxide and nitrogen oxides, all information listed in 401 KAR 59:016, Section 9(2)(a) through (i), shall be reported to the Division for each twenty-four (24) hour period.

7. If the minimum quantity of emission data as required by 401 KAR 59:016, Section 7 is not obtained for any thirty successive boiler operating days, the owner or operator shall report all the information listed in 401 KAR 59:016, Section 9(3) for that thirty (30) day period.

8. If any sulfur dioxide standards as specified in 401 KAR 59:016, Section 4(a and b) are exceeded during emergency conditions because of control system malfunction, the owner or operator shall submit a signed statement including all information as described in 401 KAR 59:016, Section 9(4).

9. For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator shall submit a signed statement pursuant to 401 KAR 59:016, Section 9(6) indicating if any changes were made in the operation of the emission control system during the period of data unavailability. Operations of control system and emissions units during periods of data unavailability are to be compared with operation of the control system and emissions units before and following the period of data unavailability.

10. The owner or operator shall submit a signed statement including all information as described in 401 KAR 59:016, Section 9(7).

11. Pursuant to 401 KAR 59:016, Section 9(8), for the purposes of the reports required under 401 KAR 59:005, Section 4, periods of excess emissions are defined as all six (6) minute periods during which the average opacity exceeds the applicable opacity standards as specified in 401 KAR 59:016, Section 3(2). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Division each calendar quarter. As the COM system is located after the PJFF as an indicator of performance for that device but before the WFGD which provides additional particulate control, in the event of an opacity exceedance, as indicated by COM data, the owner or operator may conduct a Method 9 test to verify that

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

actual opacity from the stack complies with the applicable opacity standard, in which case the owner or operator shall promptly complete any necessary repairs to the PJFF. Such events shall not be considered in excess of the applicable opacity standard for reporting or other purposes. The CEM systems for sulfur dioxide and nitrogen oxide shall be certified, operated and maintained in accordance with the applicable provisions of 40 CFR 75, compliance with which shall be deemed compliance with monitoring provisions of 40 CFR 60.49a.

b) Pursuant to 401 KAR 59:005, Section 3(3), the owner or operator shall report the number of excursions (excluding startup, shut down, malfunction data) above the opacity trigger level, date and time of excursions, opacity value of the excursions, and percentage of the COM data showing excursions above the opacity trigger level in each calendar quarter to the Division's Regional Office consistent with the reporting provisions of paragraph B.6.a.11..

c) CAM Requirements. Pursuant to 40 CFR 64.9(a) the owner or operator shall report the following information regarding its CAM plan according to the general reporting requirements specified in Section F.5. of this permit:

1. Number of exceedances or excursions;
2. Duration of each exceedance or excursion;
3. Cause of each exceedance or excursion;
4. Corrective actions taken on each exceedance or excursion;
5. Number of monitoring equipment downtime incidents;
6. Duration of each monitoring equipment downtime incident;
7. Cause of each monitoring equipment downtime incident;
8. Description of actions taken to implement a quality improvement plan and upon completion of the quality improvement plan, documentation that the plan was completed and reduced the likelihood of similar excursions or exceedances.
9. The permittee shall take a sample of fuel "as received" upon delivery schedule to the PCs. The samples taken shall be uniformly mixed to form a composite sample analyzed to determine fluoride content on a quarterly basis. This data, along with the baseline data established during the initial compliance and subsequent tests, shall be used to demonstrate compliance with the emission limits for HF.

d) The permittee shall report quarterly the twelve (12) month rolling total sulfur dioxide and nitrogen oxides emissions.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

7. Specific Control Equipment Operating Conditions:

a) Pursuant to 401 KAR 50:055, Section 2 (5), the SCR, PJFF, WFGD, and WESP, shall be operated to maintain compliance with permitted emission limitations, in accordance with manufacturer’s specifications and/or standard operating practices.

b) Pursuant to 401 KAR 59:005, Section 3(4), records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)
Emissions Unit 32 - Auxiliary Steam Boiler D

Description:
40 mmBtu/hr ·ASTM Grade No. 2-D S15 fired auxiliary steam boiler
Construction Commenced Date: Estimated 2006

Applicable Regulations:
40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, incorporated by reference in 401 KAR 60:005, Section 3(1)(e).
401 KAR 59:015, New Indirect Heat Exchangers.
40 CFR 63, Subpart DDDDD
401 KAR 63:020, Potentially Hazardous Matter or Toxic Substances.
40 CFR 60, Appendix F, Quality Assurance Procedures
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. **Operating Limitations:**
The auxiliary steam boiler, except for testing purposes, shall only operate during periods when Unit 31 is operating at less than 50 percent load. The auxiliary boiler shall not operate more than 1,000 hours in any twelve (12) consecutive months.

2. **Emission Limitations:**
a) Pursuant to 401 KAR 60:005, Section 3(1)(e), 401 KAR 59:015, Section 4(1)(c), 401 KAR 51:017, 40 CFR 60.43c(e) [per proposed revised NSPS Subpart Dc as published in the Federal Register on February 28, 2005], and 40 CFR 63 Subpart DDDDD Table 1, particulate emissions shall not exceed 0.03 lb/mmBtu heat input.

b) Pursuant to 401 KAR 60:005, Section 3(1)(e) and 401 KAR 59:015, Section 4(2)(a), emissions from the auxiliary steam boiler shall not exceed twenty (20) percent opacity based on a six-minute average except that a maximum of twenty-seven (27) percent is allowed for not more than one (1) six (6) minute period per hour.

c) Pursuant to 401 KAR 60:005, Section 3(1)(b); 401 KAR 59:015, Section 5(1)(b); and 401 KAR 51:017, the fuel oil used must meet the sulfur content standards in ASTM Grade No. 2-D S15 and cannot exceed a sulfur content of 15 ppm.

d) Pursuant to 401 KAR 51:017 and 40 CFR 63 Subpart DDDDD Table 1, carbon monoxide emissions shall not exceed 400 ppm by volume on a dry basis corrected to 3 percent oxygen and a 3-hour average.

e) Pursuant to 40 CFR 63 Subpart DDDDD Table 1, hydrogen chloride emissions shall not exceed 0.0005 lbs/mmBtu of heat input.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

3. Testing Requirements:

a) Pursuant to 401 KAR 59:005, Section 2(1) and 401 KAR 59:015, Section 8, the owner or operator shall demonstrate compliance with the applicable emission standards within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility.

b) Pursuant to 40 CFR 63.7506, a performance test to demonstrate compliance with the carbon monoxide and hydrogen chloride emission limits is not required. However the following requirements must be met.

1. To demonstrate initial compliance, a signed statement in the Notification of Compliance Status report that indicates that the unit burns only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels.

2. To demonstrate continuous compliance, records must be kept that demonstrate that the unit burned only liquid fossil fuels other than residual oil, either alone or in combination with gaseous fuels. A signed statement must be included in each semiannual compliance report that indicates that the unit burned only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels, during the reporting period.

c) Pursuant to 401 KAR 59:015, Section 8(1)(f), if the unit has operated during the previous 12 consecutive months, the owner or operator shall determine the opacity of emissions from the stack by EPA Reference Method 9 upon request by the Division.

d) See Section D for further requirements.

4. Specific Monitoring Requirements:

a) The owner or operator shall monitor the hours of operation during each twelve (12) consecutive months.

b) To demonstrate continuing compliance with the fuel oil sulfur content limitation, monitoring of operations shall consist of, on an as-received basis, fuel supplier certification of the sulfur content of the fuel oil to be combusted. The fuel supplier certification shall include the name of the oil supplier, sulfur content, and a statement that the oil complies with the specifications under the definition for distillate oil in 401 KAR 60:005

c) The fuel oil sulfur content and heating value shall be determined for the No. 2 fuel oil, as received, by fuel supplier certification.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

5. Specific Record Keeping Requirements:

a) Pursuant to 401 KAR 59:005, Section 3(4), the owner or operator of the indirect heat exchanger shall maintain a file of all measurements and performance testing measurements required by 401 KAR 59:005 recorded in a permanent form suitable for inspection.

b) Pursuant to 401 KAR 59:005, Section 3(2), the owner or operator of this unit shall maintain the records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility.

c) The owner or operator shall maintain the results of all compliance tests.

d) The owner or operator shall maintain records of hours of operation during each twelve (12) consecutive months.

e) Pursuant to 401 KAR 59:005, Section 3 (4), the owner or operator of the indirect heat exchanger shall maintain a file of all measurements, including monthly No. 2 fuel oil usage. The owner or operator shall maintain a file of the fuel supplier certification; and all other information required by 401 KAR 59:005 recorded in a permanent form suitable for inspection. The file shall be retained for at least five (5) years following the date of such measurements, maintenance, reports, and records.

f) Records of the No. 2 fuel oil used shall be maintained.

6. Specific Reporting Requirements:

a) Pursuant to 401 KAR 60:005, Section 3(1)(e), the owner or operator shall follow the applicable Reporting and Recordkeeping requirements specified in 40 CFR 60.48c.

b) Pursuant to 40 CFR 63 Subpart DDDDD, the owner or operator shall make notifications required by 40 CFR 63.7545.

c) Pursuant to 40 CFR 63 Subpart DDDDD, the owner or operator shall submit reports required by 40 CFR 63.7550.

7. Specific Control Equipment Operating Conditions:

a) Pursuant to 401 KAR 50:055, Section 5, the auxiliary steam boiler shall be operated in accordance with manufacturer's specifications and / or standard operating practices.

b) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 33 - Backup Diesel Generator

Description:
12.5 mmBtu/hr - ASTM Grade No. 2-D S15 fuel oil-fired Backup Generator without oxidation catalyst or Non-Selective Catalytic Reduction (NSCR).
Construction Commenced Date: Estimated 2006

Applicable Regulations:
401 KAR 63:002, incorporating by reference 40 CFR 63, Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:
Pursuant to 401 KAR 51:017, the backup diesel generator, except for testing purposes, shall only operate during periods when Unit 31 is operating less than 50 percent load. The backup diesel generator shall not operate more than 1,000 hours per twelve (12) consecutive months.

2. Emission Limitations:
Pursuant to 401 KAR 63:002, formaldehyde concentration in the exhaust shall not exceed 580 ppbvd at 15 percent O_2 except during periods of startup, shutdown, and malfunction.

3. Testing Requirements:

a) Pursuant to 401 KAR 63:002, the owner or operator shall demonstrate compliance with the applicable emission standards upon startup.

b) Pursuant to 401 KAR 63:002, the average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs shall not exceed the formaldehyde emission limit specified in 2.

c) Pursuant to 401 KAR 63:002, semiannual performance tests for formaldehyde will be performed to determine compliance. If compliance is demonstrated with two consecutive semiannual tests, subsequent compliance tests shall be performed on an annual basis, unless otherwise approved by the Division.

d) See Section D for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

4. Specific Monitoring Requirements:

a) Pursuant to 401 KAR 63:002, the owner or operator shall install, calibrate, maintain, and operate a continuous parameter monitoring system, or alternative method, as allowed by regulation. The operating parameters are to be approved by the Division.

b) See Section D for further requirements.

5. Specific Record Keeping Requirements:

a) The owner or operator shall maintain the results of all compliance tests.

b) The owner or operator shall maintain records of hours of operation during each twelve (12) consecutive month period.

6. Specific Reporting Requirements:

a) Pursuant to 401 KAR 60:005, Section 3(1)(e), the owner or operator shall follow the applicable Reporting and Recordkeeping requirements specified in 40 CFR 60.48c.

b) Pursuant to 40 CFR 63 Subpart ZZZZ, the owner or operator shall make notifications required by 40 CFR 63.6645.

c) Pursuant to 40 CFR 63 Subpart ZZZZ, the owner or operator shall submit reports required by 40 CFR 63.6645.

7. Specific Control Equipment Operating Conditions:

None

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 34, 35 - Fossil Fuel Handling Operations-Coal Piles (FUGITIVES)

Description:
Construction Commenced Date:
Estimated 2006

Active Northwest Fossil Fuel Pile "A"	Fuel Pile Storage and Maintenance Activities
Active Northeast Fossil Fuel Pile "B"	Fuel Pile Storage and Maintenance Activities

Control Equipment

Active Northwest Fossil Fuel Pile "A"	Compaction and Water Suppression
Active Northeast Fossil Fuel Pile "B"	Compaction and Water Suppression

Applicable Regulations:
401 KAR 63:010, Fugitive emissions.
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:

a) Pursuant to 401 KAR 51:017 and 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, as needed, but not be limited to the following:

1. Application and maintenance of asphalt, application of water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dusts;

2. Operation of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling;

3. The maintenance of paved roadways.

4. The prompt removal of earth or other material from a paved street which earth or other material has been transported thereto by trucking or other earth moving equipment or erosion by water;

5. Installation and use of compaction or other measures to suppress the dust emissions during handling.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

c) No one shall allow earth or other material being transported by truck or earth moving equipment to be deposited onto a paved street or roadway, pursuant to 401 KAR 63:010, Section 4.

d) Pursuant to 401 KAR 51:017, the owner or operator shall apply compaction and water suppression control methods as BACT.

2. <u>Emission Limitations:</u>
None

3. <u>Testing Requirements:</u>
40 CFR 60 Appendix A, Reference Method 22 shall be used to determine opacity upon request by the Division.

4. <u>Specific Monitoring Requirements:</u>

a) The owner or operator shall perform a qualitative visual observation on a weekly basis and maintain a log of the observations and corrective actions.

b) See Section F for further requirements.

5. <u>Specific Record Keeping Requirements:</u>

a) Records of the fossil fuels received and processed shall be maintained for emissions inventory purposes.

b) Annual records estimating the tonnage hauled on plant roadways shall be maintained for emissions inventory purposes.

c) The owner or operator shall maintain a log of the date, time and results of the monitoring required in Subsection 4 above.

6. <u>Specific Reporting Requirements:</u>
See Section F for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

7. Specific Control Equipment Operating Conditions:

a) Pursuant to 401 KAR 50:055, Section 5 and 401 KAR 51:017, the dust water suppressant system for the coal stockpile operations shall be maintained and operated to ensure the emission units are in compliance with applicable requirements of 401 KAR 63:010, and in accordance with manufacturer's specifications and standard operating practices.

b) Plant roadways shall be paved and controlled with water as necessary to comply with 401 KAR 63:010.

c) Pursuant to 401 KAR 59:005, Section 3(4), records regarding the maintenance of the control equipment shall be maintained.

d) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 36, 37, 38, 39 -- Fossil Fuel Handling Operations, Dust Control Devices, and Associated Systems (Please refer to Units 7, 8 and 9 for additional existing fossil fuel handling operation information)

Description:

Construction Commenced Date: on or Before 1990

Continuous Barge Unloader –

One Barge Unloader Bin

Conveyor System -

Conveyor Belt A:	From Continuous Barge Unloader to Conveyor B
Conveyor Belt B:	From Conveyor A to Transfer House/Conveyor C
Conveyor Belt C:	From Transfer House to Coal Sample House Bin
Conveyor Belt D:	From Coal Sample House Bin to Conveyor E1 or S
Conveyor Belt E1:	From Conveyor D to Active Storage and Crusher House
Conveyor Belts F1 & F2:	From Crusher House to Conveyors G1 & G2
Conveyor Belts G1 & G2:	From Conveyors F1 & F2 to Unit 1 & 2 Coal Silos
Conveyor Belt S:	From Conveyor D to One Inactive Fossil Fuel Pile
Reclaim Hopper & Conveyor Belt R1:	From One Inactive Fossil Fuel Pile to Crusher House

Crusher House -

Two crushers, fossil fuel crusher bin, and fuel blender: Crusher House Activities

Construction Commenced Date: Estimated 2006

Power House –

Six Unit 2 fossil fuel silos: Unit 2 Coal Storage

Conveyor System –

Conveyor Belt E2:	From Unit 2 Active Coal Piles "A & B" to Crusher House
Fuel Blending System:	From Active Coal Storage to Conveyor E2

Control Equipment

EU#36-Barge Unloader Dust Collector (CDC01):	Conveyors A&B
EU#37-U/R Reclaim Vault Dust Collector (CDC02):	Drop from Coal Feeders 1-7 to Conveyor E2
EU#38-Coal Crusher Dust Collector (CDC03):	Coal Crusher House Activities
EU#39-Unit 2 Coal Silo Dust Collector (CDC04):	Conveyors F1&2 and Drop to G1&2; Unit 2 Coal Silos

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Description

Conveyors: Enclosures, water suppression, low drops, and baghouse filters, hoods
Conveyor S: Stackout Chute

Operating Rate–

Continuous Barge Unloader	Transfer Rates
One Barge Unloader	5,500 tons/hour

Conveyor System -

Conveyor Belt A:	5,500 tons/hour
Conveyor Belt B:	5,500 tons/hour
Conveyor Belt C:	5,500 tons/hour
Conveyor Belt D:	3,000 tons/hour
Conveyor Belt E1:	2,640 tons/hour
Conveyor Belt E2:	1,320 tons/hour
Conveyor Belts F1 & F2:	1,320 tons/hour
Conveyors G1 & G2	1.320 tons/hour
Conveyor Belt S:	1,650 tons/hour
Reclaim Hopper & Conveyor Belt R1:	1,320 tons/hour
Unit2 Fuel Blending System:	800 tons/hour

Crusher House -

Two crushers, fossil fuel crusher bin, and fuel blender: 3,600 tons/hour

Power House -

Six unit 2 fossil fuel silos: 800 tons/hour

Applicable Regulations:

401 KAR 60:005, incorporating by reference 40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants for units commenced after October 24, 1974
401 KAR 51:017, Prevention of Significant Deterioration of Air Quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:

Pursuant to 401 KAR 51:017, the owner or operator shall install the following dust collectors as BACT:

a) Barge Unloader Dust Collector

b) U/R Reclaim Vault Dust Collector

c) Coal Crusher Dust Collector

d) Unit 2 Coal Silo Dust Collector

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED

2. **Emission Limitations:**
   a) Pursuant to 401 KAR 60:005 incorporating by reference 40 CFR 60.252, the owner or operator subject to the provisions of this regulation shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.

   b) Pursuant to 401 KAR 51:017, the dust collectors utilized shall exhibit a particulate design control efficiency of at least 99%.

3. **Testing Requirements:**
   Pursuant to 401 KAR 60:005, Section 3(1)(ff) incorporating by reference, 40 CFR 60.254, EPA Reference Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity upon request by the Division.

4. **Specific Monitoring Requirements:**
   The owner or operator shall perform a qualitative visual observation of the opacity of emissions from each stack on a weekly basis and maintain a log of the observations. If visible emissions from any stack are seen, the owner or operator shall determine the opacity of emissions by Reference Method 9 and instigate an inspection of the control equipment making any necessary repairs.

5. **Specific Record Keeping Requirements:**
   a) The owner or operator shall maintain the records of amount of coal received and processed.

   b) The owner or operator shall maintain the results of all compliance tests. The owner or operator shall record each week, the date and time of each observation and opacity of visible emissions monitoring. In case of exceedances, the owner or operator must record the reason (if known) and the measures taken to minimize or eliminate exceedances.

6. **Specific Reporting Requirements:**
   See Section F for further requirements.

7. **Specific Control Equipment Operating Conditions:**
   a) Pursuant to 401 KAR 50:055, Section 5, the enclosures/partial enclosures, baghouses, bin vent filters, conveyor systems, fuel blending operations, fossil fuel storage silos, and stackout chute shall be maintained and operated to ensure the emission units are in compliance with applicable requirements of 40 CFR 60, Subpart Y and in accordance with manufacturer's specifications and/or standard operating practices.

   b) Pursuant to 401 KAR 59:005, Section 3(4), records regarding the maintenance and use/operation of the control equipment listed in 7(a) shall be maintained.

   c) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED

Emissions Units: 40 - Limestone Handling Operations, Dust Control Devices, and Associated Systems

Description:
Construction Commenced Date: Estimate 2006

Stockpile/Stackout Operations:

Active Limestone Pile	Limestone Storage Activities
Active Limestone Pile Reclaimer	Limestone Reclaim Activities

Control Equipment

Active Limestone Pile	Low Drop/Enclosure/Dust Collector (LDC01)
Active Limestone Pile Reclaimer	Enclosure/Dust Collector (LDC01)
EU#40-Limestone Dust Collector (LDC01)	Conveyor B onto Active Pile and Active Pile Reclaimer onto Conveyor C

Operating Rate

Active Limestone Pile	N/A
Active Limestone Pile Reclaimer	200 tons/hour

Applicable Regulations:
401 KAR 60.670, New Nonmetallic Mineral Processing Plants, incorporating by reference 40 CFR 60, Subpart OOO – Nonmetallic Mineral Processing Plants, applies to the emissions unit listed above, commenced after August 31, 1983
401 KAR 51:017, Prevention of Significant Deterioration of Air Quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:
Pursuant to 401 KAR 51:017, the owner or operator shall install a dust collector as BACT.

2. Emission Limitations:

a) Pursuant to 401 KAR 60.670, incorporating by reference 40 CFR 60.672(e), no owner or operator shall cause to be discharged into the atmosphere from any building enclosing any transfer point on a conveyor belt or any other emissions unit any visible fugitive emissions.

b) Pursuant to 401 KAR 51:017 and 401 KAR 60:670, emissions of particulate shall be controlled by dust collectors.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c) Pursuant to 401 KAR 60:670, specifically 40 CFR 60.672(a), stack emissions of particulate shall not exceed 0.05 gr/dscm and shall not exhibit greater than 7% opacity.

d) Pursuant to 401 KAR 60:607, specifically 40 CFR 60.672(b), fugitive emissions of particulate shall not exhibit greater than 10% opacity.

3. Testing Requirements:

In determining compliance with 401 KAR 60:670, incorporating by reference 40 CFR 60.672(e), for fugitive emissions from buildings, the owner(s) or operator(s) shall determine fugitive emissions while all emissions units are operating in accordance with EPA Reference Method 22, annually.

4. Specific Monitoring Requirements:

The owner or operator shall inspect the control equipment weekly and make repairs as necessary to assure compliance.

5. Specific Record Keeping Requirements:

Records of the limestone processed shall be maintained for emissions inventory purposes.

6. Specific Reporting Requirements:

a) Pursuant to 401 KAR 60:670, incorporating by reference 40 CFR 60.676, the owner(s) or operator(s) of any emissions unit shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards of 40 CFR 60.672 including reports of observations using Method 22 to demonstrate compliance.

b) See Section F for further requirements.

7. Specific Control Equipment Operating Conditions:

a) Pursuant to 401 KAR 50:055, Section 5, the dust collector and enclosures shall be maintained and operated to ensure the emission units are in compliance with applicable requirements of 40 CFR 60, Subpart OOO and in accordance with manufacturer's specifications and/or standard operating practices.

b) Pursuant to 401 KAR 50:050, Section 1, records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED

Unit: 41 - Linear Mechanical Draft Cooling Tower (11 cells)

Description:
Control Equipment: 0.0005% Drift Eliminators
Circulating Water Rate: 173,120 Gallons per Minute
Construction Commenced Date: Estimated 2006

Applicable Regulations:
401 KAR 63:010, Fugitive emissions
401 KAR 51:017, Prevention of Significant Deterioration of Air Quality applicable to major construction or modification commenced after September 22, 1982.

1. **Operating Limitations:**
   a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.

   b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

2. **Emission Limitations:**
   a) Pursuant to 401 KAR 51:017, the cooling tower shall utilize 0.0005% Drift Eliminators.

   b) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.

3. **Testing Requirements:**
   Initial performance test to verify drift percent achieved by the drift eliminator will be conducted based on the Cooling Technology Institute (CTI) Acceptance Test Code (ATC) # 140

4. **Specific Monitoring Requirements:**

   The permittee shall monitor total dissolved solids content of the circulating water on a monthly basis.

5. **Specific Record Keeping Requirements:**
   a) The owner or operator shall maintain records of the manufacturer's design of the Drift Eliminators.

   b) The owner or operator shall maintain records of maximum pumping capacity and monthly records of the total dissolved solids content.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

6. **Specific Reporting Requirements:**
See Section F for further requirements.

7. **Specific Control Equipment Operating Conditions:**

a) Pursuant to 401 KAR 50:055, Section 5, the drift eliminators shall be maintained and operated to ensure the emission units are in compliance with applicable requirements of 401 KAR 63:010 and in accordance with manufacturer's specifications and/or standard operating practices.

b) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED

Unit: 42 - **Fly Ash Storage Silo and Dust Control Device**

Description:
Construction Commenced Date: Estimate 2006

Fly Ash Silo Bins Fly Ash Storage Activities

Control Equipment

EU#42-Fly Ash Dust Collector (FDC01) Fly Ash from Units 1 and 31 into Fly Ash Silo Bins and Fly Ash from Fly Ash Silo Bins into Dry Bulk Trailers with Tractors

Operating Rate

Fly Ash Silo Bins Material Throughput: 33 tons/hour each

Applicable Regulations:
401 KAR 59:010, New Process Operations, applicable to an emission unit, which commenced on or after 1972
401 KAR 51:017, Prevention of Significant Deterioration of Air Quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:
Pursuant to 401 KAR 51:017, the owner or operator shall install a dust collector as BACT.

2. Emission Limitations:

a) Pursuant to 401 KAR 59:010, Section 3(1), the owner or operator shall not cause to be discharged into the atmosphere from any of the above listed units emissions greater than twenty (20) percent opacity.

b) Pursuant to 401 KAR 59:010, particulate matter emissions from the bin dust collector shall not exceed [$3.59 (P)^{0.62}$] lbs/hr based on a three-hour average, where P is the material throughput rate in tons/hour.

3. Testing Requirements:
None

4. Specific Monitoring Requirements:
The owner or operator shall perform a qualitative visual observation of the opacity of emissions from the stack on a weekly basis and maintain a log of the observations. If visible emissions from any stack included in this emission unit are seen, then the owner or operator shall determine the opacity of emissions by Reference Method 9 and perform an inspection of the control equipment for any necessary repairs.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED

5. Specific Record Keeping Requirements:

a) The owner or operator shall maintain the records of amount of fly ash processed.

b) Pursuant to 401 KAR 59:005, Section 3(4), the owner or operator shall maintain the results of all compliance tests and calculations.

c) The owner or operator shall record each week the date, time and opacity of the visible emissions monitoring. In case of an exceedance, the owner or operator must record the reason (if known) and the measures taken to minimize or eliminate the exceedance.

6. Specific Reporting Requirements:

See Section F for further requirements.

7. Specific Control Equipment Operating Conditions:

a) Pursuant to 401 KAR 50:055, Section 5, the dust collector equipment shall be maintained and operated to ensure the emission unit is in compliance with applicable requirements of 401 KAR 59:010 and in accordance with manufacturer's specifications and/or standard operating practices

b) Pursuant to 401 KAR 59:005, Section 3(4), records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

SECTION C - INSIGNIFICANT ACTIVITIES

The following listed activities have been determined to be insignificant activities for this source pursuant to 401 KAR 52:020, Section 6. While these activities are designated as insignificant the permittee must comply with the applicable regulation and some minimal level of periodic monitoring may be necessary. Process and emission control equipment at each insignificant activity subject to a general applicable regulation shall be inspected monthly and qualitative visible emission evaluation made. The results of the inspections and observations shall be recorded in a log, noting color, duration, density (heavy or light), cause and any conservative actions taken for any abnormal visible emissions.

Description		Generally Applicable Regulation
1.	Two station #2 fuel oil tanks, each 100,000 gallons (401 KAR 59:050), and auxiliary boiler day tank storing #2 fuel oil with a size of 16,000 gallons. General recordkeeping requirements - 40 CFR 60.116b(a) and (b)	401 KAR 59:050 40 CFR 60.116b(a) and (b)
2.	Metal degreaser using a maximum throughput of 832 gallons/year solvent.	NA
3.	3,000 gallon unleaded gasoline storage tank.	NA
4.	3,000 gallon diesel storage tank.	NA
5.	1,100 gallon used oil storage tank.	NA
6.	1,100 gallon #1 fuel oil tank.	NA
7.	Fly ash collection system	401 KAR 59:010
8.	Infrequent evaporation of boiler cleaning solutions.	NA
9.	Infrequent burning of De Minimis quantities of used oil for energy recovery.	NA
10.	Paved and Unpaved Roads.	401 KAR 63:010
11.	Preheater (for CTs Units 9 & 10) Max. Heat Input 10.9 mmBtu/hr.	401 KAR 59:010
12.	Preheater (for CTs Units 11 &12) Max. Heat Input 10.9 mmBtu/hr.	401 KAR 59:010
13.	Preheater (for CTs Units 13 & 14) Max. Heat Input 10.9 mmBtu/hr.	401 KAR 59:010
14.	Gypsum Storage Piles	401 KAR 63:010
15.	Coal and Limestone Storage Piles (Inactive Outdoor Piles)	401 KAR 63:010
16.	Bottom Ash and Debris Collection Basin	401 KAR 63:010
17.	Bottom Ash Reclaim Operation	401 KAR 63:010
18.	Three dry bulk fly ash transport trailers	401 KAR 59:010
19.	Maintenance Shop Activities	NA
20.	Miscellaneous Water Storage Tanks	NA
21.	Anhydrous Ammonia Storage Tanks	401 KAR 68
22.	Fire Water Pump Engines	NA
23.	Three dry bulk fly ash transport trailers	401 KAR 59:010

SECTION D - SOURCE EMISSION LIMITATIONS AND TESTING REQUIREMENTS

1. As required by Section 1b of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26; compliance with annual emissions and processing limitations contained in this permit, shall be based on emissions and processing rates for any twelve (12) consecutive months.

2. Compliance with visible emission limitations for indirect heat exchanger Unit 01, shall be determined by using EPA reference Method 9. Alternatively, the owner or operator may use COM in determining compliance with opacity.

3. Conditions in permit V-02-043 Revision 1 and PSD permit V-01-012 were merged into one source-wide permit. Limitations from both permits were combined into this permit.

4. Nitrogen oxides, sulfur dioxide, PM (filterable), formaldehyde, visible emissions (opacity), mercury, and carbon monoxide emissions, measured by applicable reference methods, or an equivalent or alternative method specified in 40 C.F.R. Chapter I, or by a test method specified in the state implementation plan shall not exceed the respective limitations specified herein.

5. Unit 31 shall be performance tested initially for compliance with the emission standards for PM/PM_{10} (filterable and condensable), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon monoxide (CO), VOCs, mercury, and H_2SO_4, lead and fluorides by applicable reference methods, or by equivalent or alternative test methods specified in this permit or approved by the cabinet or U.S. EPA. For Unit 31 annual performance tests for PM/PM_{10}, VOCs, and lead will be conducted.

6. After the initial compliance test for Unit 31, and CEMS/COMs certification as stated in 401 KAR 50:055, continuing compliance with the emission standards shall be determined by continuous monitoring systems for NO_x, CO, PM/PM_{10}, mercury, and SO_2. Continuing compliance with the emission standards for H_2SO_4 mist and Fluorides shall be determined by following provision of the CAM plan in Section B of this permit.

7. The 12-month rolling total emissions from Units 31, 32, 33, and emergency fire water pump engine shall be less than: 1,523 NO_x tons, 3,264 SO_2 tons, and 0.55 lead tons.

8. The permittee shall evaluate the relationship between CO and VOC during the initial and annual stack tests. Results of this evaluation shall be submitted to the Division within sixty days after submitting the annual test results.

SECTION E - SOURCE CONTROL EQUIPMENT REQUIREMENTS

Pursuant to 401 KAR 50:055, Section 2(5), at all times, including periods of startup, shutdown and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

SECTION F - MONITORING, RECORD KEEPING, AND REPORTING REQUIREMENTS

1. When continuing compliance is demonstrated by periodic testing or instrumental monitoring, the permittee shall compile records of required monitoring information that include:
   a. Date, place as defined in this permit, and time of sampling or measurements.
   b. Analyses performance dates;
   c. Company or entity that performed analyses;
   d. Analytical techniques or methods used;
   e. Analyses results; and
   f. Operating conditions during time of sampling or measurement.

   [Section 1b (IV)1 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

2. Records of all required monitoring data and support information, including calibrations, maintenance records, and original strip chart recordings, and copies of all reports required by the Division for Air Quality, shall be retained by the permittee for a period of five years and shall be made available for inspection upon request by any duly authorized representative of the Division for Air Quality [Sections 1b(IV) 2 and 1a(8) of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

3. In accordance with the requirements of 401 KAR 52:020 Section 3(1)h the permittee shall allow authorized representatives of the Cabinet to perform the following during reasonable times:
   a. Enter upon the premises to inspect any facility, equipment (including air pollution control equipment), practice, or operation;
   b. To access and copy any records required by the permit:
   c. Inspect, at reasonable times, any facilities, equipment (including monitoring and pollution control equipment), practices, or operations required by the permit. Reasonable times are defined as during all hours of operation, during normal office hours; or during an emergency.
   d. Sample or monitor, at reasonable times, substances or parameters to assure compliance with the permit or any applicable requirements.
   e. Reasonable times are defined as during all hours of operation, during normal office hours; or during an emergency.

4. No person shall obstruct, hamper, or interfere with any Cabinet employee or authorized representative while in the process of carrying out official duties. Refusal of entry or access may constitute grounds for permit revocation and assessment of civil penalties.

5. Summary reports of any monitoring required by this permit, other than continuous emission or opacity monitors, shall be submitted to the Regional Office listed on the front of this permit at least every six (6) months during the life of this permit, unless otherwise stated in this permit. For emission units that were still under construction or which had not commenced operation at the end of the 6-month period covered by the report and are subject to monitoring requirements in this permit, the report shall indicate that no monitoring was performed during

SECTION F - MONITORING, RECORD KEEPING, AND REPORTING REQUIREMENTS (CONTINUED)

the previous six months because the emission unit was not in operation [Section 1b (V)1 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

6. The semi-annual reports are due by January 30th and July 30th of each year. Data from the continuous emission and opacity monitors shall be reported to the Technical Services Branch in accordance with the requirements of 401 KAR 59:005, General Provisions, Section 3(3). All reports shall be certified by a responsible official pursuant to 401 KAR 52:020 Section 23. All deviations from permit requirements shall be clearly identified in the reports.

7. In accordance with the provisions of 401 KAR 50:055, Section 1 the owner or operator shall notify the Regional Office listed on the front of this permit concerning startups, shutdowns, or malfunctions as follows:
   a. When emissions during any planned shutdowns and ensuing startups will exceed the standards, notification shall be made no later than three (3) days before the planned shutdown, or immediately following the decision to shut down, if the shutdown is due to events which could not have been foreseen three (3) days before the shutdown.
   b. When emissions due to malfunctions, unplanned shutdowns and ensuing startups are or may be in excess of the standards, notification shall be made as promptly as possible by telephone (or other electronic media) and shall be submitted in writing upon request.

8. The owner or operator shall report emission related exceedances from permit requirements including those attributed to upset conditions (other than emission exceedances covered by Section F.7. above) to the Regional Office listed on the front of this permit within *30 days*. Other deviations from permit requirements shall *be included in the semiannual report required by Section F.6* [Section 1b (V) 3, 4. of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

9. Pursuant to 401 KAR 52:020, Permits, Section 21, the permittee shall certify compliance with the terms and conditions contained in this permit, by completing and returning a Compliance Certification Form (DEP 7007CC) (or an alternative approved by the regional office) to the Regional Office listed on the front of this permit and the U.S. EPA in accordance with the following requirements:
   a. Identification of the term or condition;
   b. Compliance status of each term or condition of the permit;
   c. Whether compliance was continuous or intermittent;
   d. The method used for determining the compliance status for the source, currently and over the reporting period, and
   e. For an emissions unit that was still under construction or which has not commenced operation at the end of the 12-month period covered by the annual compliance certification, the permittee shall indicate that the unit is under construction and that compliance with any applicable requirements will be demonstrated within the timeframes specified in the permit.

SECTION F - MONITORING, RECORD KEEPING, AND REPORTING REQUIREMENTS (CONTINUED)

f. The certification shall be postmarked by January 30th of each year. Annual compliance certifications should be mailed to the following addresses:

Division for Air Quality Florence Regional Office 8020 Veterans Memorial drive Suite 110, Florence, KY 41042	U.S. EPA Region 4 Air Enforcement Branch Atlanta Federal Center 61 Forsyth St. Atlanta, GA 30303-8960

Division for Air Quality
Central Files
803 Schenkel Lane
Frankfort, KY 40601

10. In accordance with 401 KAR 52:020, Section 22, the permittee shall provide the Division with all information necessary to determine its subject emissions within thirty (30) days of the date the KYEIS emission survey is mailed to the permittee.

11. Results of performance test(s) required by the permit shall be submitted to the Division by the source or its representative within forty-five days or sooner if required by an applicable standard, after the completion of the fieldwork.

SECTION G - GENERAL PROVISIONS

(a) General Compliance Requirements

1. The permittee shall comply with all conditions of this permit. Noncompliance shall be a violation of 401 KAR 52:020 and of the Clean Air Act and is grounds for enforcement action including but not limited to termination, revocation and reissuance, revision or denial of a permit [Section 1a, 3 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020 Section 26].

2. The filing of a request by the permittee for any permit revision, revocation, reissuance, or termination, or of a notification of a planned change or anticipated noncompliance, shall not stay any permit condition [Section 1a, 6 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

3. This permit may be revised, revoked, reopened and reissued, or terminated for cause in accordance with 401 KAR 52:020, Section 19. The permit will be reopened for cause and revised accordingly under the following circumstances:
   a. If additional requirements become applicable to the source and the remaining permit term is three (3) years or longer. In this case, the reopening shall be completed no later than eighteen (18) months after promulgation of the applicable requirement. A reopening shall not be required if compliance with the applicable requirement is not required until after the date on which the permit is due to expire, unless this permit or any of its terms and conditions have been extended pursuant to 401 KAR 52:020, Section 12;
   b. The Cabinet or the U. S. EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements;
   c. The Cabinet or the U. S. EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit;
   d. If any additional applicable requirements of the Acid Rain Program become applicable to the source.

   Proceedings to reopen and reissue a permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists. Reopenings shall be made as expeditiously as practicable. Reopenings shall not be initiated before a notice of intent to reopen is provided to the source by the Division, at least thirty (30) days in advance of the date the permit is to be reopened, except that the Division may provide a shorter time period in the case of an emergency.

4. The permittee shall furnish information upon request of the Cabinet to determine if cause exists for modifying, revoking and reissuing, or terminating the permit; or to determine compliance with the conditions of this permit [Section 1a, 7,8 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

SECTION G - GENERAL PROVISIONS (CONTINUED)

5. The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such facts or corrected information to the permitting authority [401 KAR 52:020, Section 7(1)].

6. Any condition or portion of this permit which becomes suspended or is ruled invalid as a result of any legal or other action shall not invalidate any other portion or condition of this permit [Section 1a, 14 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

7. The permittee shall not use as a defense in an enforcement action the contention that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance [Section 1a, 4 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

8. Except for requirements identified in this permit as state-origin requirements, all terms and conditions shall be enforceable by the United States Environmental Protection Agency and citizens of the United States [Section 1a, 15 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

9. This permit shall be subject to suspension if the permittee fails to pay all emissions fees within 90 days after the date of notice as specified in 401 KAR 50:038, Section 3(6) [Section 1a, 10 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

10. Nothing in this permit shall alter or affect the liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance [401 KAR 52:020, Section 11(3)(b)].

11. This permit does not convey property rights or exclusive privileges [Section 1a, 9 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

12. Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits, licenses, or approvals required by the Kentucky Cabinet for Environmental and Public Protection or any other federal, state, or local agency.

13. Nothing in this permit shall alter or affect the authority of U.S. EPA to obtain information pursuant to Federal Statute 42 USC 7414, Inspections, monitoring, and entry [401 KAR 52:020, Section 11(3)(d)].

14. Nothing in this permit shall alter or affect the authority of U.S. EPA to impose emergency orders pursuant to Federal Statute 42 USC 7603, Emergency orders [401 KAR 52:020, Section 11(3)(a)].

SECTION G - GENERAL PROVISIONS (CONTINUED)

15. This permit consolidates the authority of any previously issued PSD, NSR, or Synthetic minor source preconstruction permit terms and conditions for various emission units and incorporates all requirements of those existing permits into one single permit for this source.

16. Pursuant to 401 KAR 52:020, Section 11, a permit shield shall not protect the owner or operator from enforcement actions for violating an applicable requirement prior to or at the time of issuance. Compliance with the conditions of a permit shall be considered compliance with:
(a) Applicable requirements that are included and specifically identified in the permit and
(b) Non-applicable requirements expressly identified in this permit.

17. *The permittee shall submit a startup and shut down plan to implement the requirements of this permit and 401 KAR 50:055. The plan shall be submitted at least ninety (90) days prior to the startup of the Unit #2 for the Division's approval. The startup/shutdown plan will be accessible for public review at the Division's central office and the regional office.*

18. *The permittee shall provide the Division the final design information consistent with Kentucky Open Records Act. The design plan will be accessible for public review at the Division's central office and the regional office*

(b) Permit Expiration and Reapplication Requirements

1. This permit shall remain in effect for a fixed term of five (5) years following the original date of issue. Permit expiration shall terminate the source's right to operate unless a timely and complete renewal application has been submitted to the Division at least six months prior to the expiration date of the permit. Upon a timely and complete submittal, the authorization to operate within the terms and conditions of this permit, including any permit shield, shall remain in effect beyond the expiration date, until the renewal permit is issued or denied by the Division [401 KAR 52:020, Section 12].

2. The authority to operate granted shall cease to apply if the source fails to submit additional information requested by the Division after the completeness determination has been made on any application, by whatever deadline the Division sets [401 KAR 52:020 Section 8(2)].

(c) Permit Revisions

1. A minor permit revision procedure may be used for permit revisions involving the use of economic incentive, marketable permit, emission trading, and other similar approaches, to the extent that these minor permit revision procedures are explicitly provided for in the SIP or in applicable requirements and meet the relevant requirements of 401 KAR 52:020, Section 14(2).

SECTION G - GENERAL PROVISIONS (CONTINUED)

2. This permit is not transferable by the permittee. Future owners and operators shall obtain a new permit from the Division for Air Quality. The new permit may be processed as an administrative amendment if no other change in this permit is necessary, and provided that a written agreement containing a specific date for transfer of permit responsibility coverage and liability between the current and new permittee has been submitted to the permitting authority within ten (10) days following the transfer.

(d) Construction, Start-Up, and Initial Compliance Demonstration Requirements
Pursuant to a duly submitted application the Kentucky Division for Air Quality hereby authorizes the construction of the equipment described herein, emission points 31-42 in accordance with the terms and conditions of this permit.

1. Construction of any process and/or air pollution control equipment authorized by this permit shall be conducted and completed only in compliance with the conditions of this permit.

2. Within thirty (30) days following commencement of construction and within fifteen (15) days following start-up and attainment of the maximum production rate specified in the permit application, or within fifteen (15) days following the issuance date of this permit, whichever is later, the permittee shall furnish to the Regional Office listed on the front of this permit in writing, with a copy to the Division's Frankfort Central Office, notification of the following:
   a. The date when construction commenced.
   b. The date of start-up of the affected facilities listed in this permit.
   c. The date when the maximum production rate specified in the permit application was achieved.

3. Pursuant to 401 KAR 52:020, Section 3(2), unless construction is commenced within eighteen (18) months after the permit is issued, or begins but is discontinued for a period of eighteen (18) months or is not completed within a reasonable timeframe then the construction and operating authority granted by this permit for those affected facilities for which construction was not completed shall immediately become invalid. Upon written request, the Cabinet may extend these time periods if the source shows good cause.

4. For those affected facilities for which construction is authorized by this permit, a source shall be allowed to construct with the proposed permit. Operational or final permit approval is not granted by this permit until compliance with the applicable standards specified herein has been demonstrated pursuant to 401 KAR 50:055. If compliance is not demonstrated within the prescribed timeframe provided in 401 KAR 50:055, the source shall operate thereafter only for the purpose of demonstrating compliance, unless otherwise authorized by Section I of this permit or order of the Cabinet.

SECTION G - GENERAL PROVISIONS (CONTINUED)

5. This permit shall allow time for the initial start-up, operation, and compliance demonstration of the affected facilities listed herein. However, within sixty (60) days after achieving the maximum production rate at which the affected facilities will be operated but not later than 180 days after initial start-up of such facilities, the permittee shall conduct either a performance demonstration or test as required on the affected facilities in accordance with 401 KAR 50:055, General compliance requirements. These performance tests must also be conducted in accordance with General Provisions G(d)7 of this permit and the permittee must furnish to the Division for Air Quality's Frankfort Central Office a written report of the results of such performance test

(d) Construction, Start-Up, and Initial Compliance Demonstration Requirements (continued)

6. Terms and conditions in this permit established pursuant to the construction authority of 401 KAR 51:017 or 401 KAR 51:052 shall not expire.

7. At least one month prior to the date of the required performance test, the permittee shall complete and return a Compliance Test Protocol using the current approved format, to the Division's Frankfort Central Office. Pursuant to 401 KAR 50:045, Section 5, the Division shall be notified of the actual test date at least ten (10) days prior to the test.

8. Pursuant to 401 KAR 50:045 Section 5 in order to demonstrate that a source is capable of complying with a standard at all times, a performance test shall be conducted under normal conditions that are representative of the source’s operations and create the highest rate of emissions. If [When] the maximum production rate represents a source’s highest emissions rate and a performance test is conducted at less than the maximum production rate, a source shall be limited to a production rate of no greater than 110 percent of the average production rate during the performance tests. If and when the facility is capable of operation at the rate specified in the application, the source may retest to demonstrate compliance at the new production rate. The Division for Air Quality may waive these requirement on a case-by-case basis if the source demonstrates to the Division's satisfaction that the source is in compliance with all applicable requirements..

(e) Acid Rain Program Requirements

1. If an applicable requirement of Federal Statute 42 USC 7401 through 7671q (the Clean Air Act) is more stringent than an applicable requirement promulgated pursuant to Federal Statute 42 USC 7651 through 7651o (Title IV of the Act), both provisions shall apply, and both shall be state and federally enforceable.

2. The source shall comply with all requirements and conditions of the Title IV, Acid Rain Permit contained in Section J of this document and the Phase II permit application (including the Phase II NO_x compliance plan, if applicable) issued for this source. The source shall also comply with all requirements of any revised or future acid rain permit(s) issued to this source.

SECTION G - GENERAL PROVISIONS (CONTINUED)

(f) Emergency Provisions

1. Pursuant to 401 KAR 52:020 Section 24(1), an emergency shall constitute an affirmative defense to an action brought for the noncompliance with the technology-based emission limitations if the permittee demonstrates through properly signed contemporaneous operating logs or relevant evidence that:
    a. An emergency occurred and the permittee can identify the cause of the emergency;
    b. The permitted facility was at the time being properly operated;
    c. During an emergency, the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards or other requirements in the permit; and
    d. Pursuant to 401 KAR 52:020, 401 KAR 50:055, and KRS 224.01-400, the permittee notified the Division as promptly as possible and submitted written notice of the emergency to the Division when emission limitations are exceeded due to an emergency. The notice shall include a description of the emergency, steps taken to mitigate emissions, and corrective actions taken.
    e. This requirement does not relieve the source from other local, state or federal notification requirements.

2. Emergency conditions listed in General Condition (f)1 above are in addition to any emergency or upset provision(s) contained in an applicable requirement [401 KAR 52:020, Section 24(3)].

3. In an enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof [401 KAR 52:020, Section 24(2)].

(g) Risk Management Provisions

1. The permittee shall comply with all applicable requirements of 401 KAR Chapter 68, Chemical Accident Prevention, which incorporates by reference 40 CFR 68, Risk Management Plan provisions. If required, the permittee shall comply with the Risk Management Program and submit a Risk Management Plan to:

    RMP Reporting Center
    P.O. Box 1515
    Lanham-Seabrook, Maryland 20703-1515

2. If requested, submit additional relevant information to the Division or the U.S. EPA.

SECTION G - GENERAL PROVISIONS (CONTINUED)

(h) Ozone depleting substances

1. The permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR 82, Subpart F, except as provided for Motor Vehicle Air Conditioners (MVACs) in Subpart B:
   a. Persons opening appliances for maintenance, service, repair, or disposal shall comply with the required practices contained in 40 CFR 82.156.
   b. Equipment used during the maintenance, service, repair, or disposal of appliances shall comply with the standards for recycling and recovery equipment contained in 40 CFR 82.158.
   c. Persons performing maintenance, service, repair, or disposal of appliances shall be certified by an approved technician certification program pursuant to 40 CFR 82.161.
   d. Persons disposing of small appliances, MVACs, and MVAC-like appliances (as defined at 40 CFR 82.152) shall comply with the recordkeeping requirements pursuant to 40 CFR 82.166

(i) Ozone depleting substances continued

   e. Persons owning commercial or industrial process refrigeration equipment shall comply with the leak repair requirements pursuant to 40 CFR 82.156.
   f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant shall keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR 82.166.

2. If the permittee performs service on motor (fleet) vehicle air conditioners containing ozone-depleting substances, the source shall comply with all applicable requirements as specified in 40 CFR 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

SECTION H - ALTERNATE OPERATING SCENARIOS

None

SECTION I - COMPLIANCE SCHEDULE

None

SECTION J – ACID RAIN

TITLE IV PHASE II ACID RAIN

ACID RAIN PERMIT CONTENTS

1) Statement of Basis

2) SO_2 allowances allocated under this permit and NO_x requirements for each affected unit.

3) Comments, notes and justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements or conditions.

4) The permit application submitted for this source. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the Phase II Application and the Phase II NO_x Compliance Plan.

5) Summary of Actions

- **Statement of Basis:**

Statutory and Regulatory Authorities: In accordance with KRS 224.10-100 and Titles IV and V of the Clean Air Act, the Kentucky Natural Resources and Environmental Protection Cabinet, Division for Air Quality issues this permit pursuant to 401 KAR 52:020, Permits, 401 KAR 52:060, Acid Rain Permit, and Federal Regulation 40 CFR 76. (Unit 1 only)

SECTION J – ACID RAIN (CONTINUED)

PERMIT (Conditions)

Plant Name: Louisville Gas & Electric Company	
Affected Units: 1	

1. SO_2 Allowance Allocations and NO_x Requirements for the affected unit:

SO_2 Allowances	**Year**				
	2003	2004	2005	2006	2007
Tables 2, 3 or 4 of 40 CFR 73	9,634*	9,634*	9,634*	9,634*	9,634*

NO_x Requirements	
NO_x Limits	Pursuant to 40 CFR 76, the Kentucky Division for Air Quality approves the NO_x Early Reduction Plan for this unit. This plan is effective for calendar year 2003 through 2008. Under this NO_x compliance plan, this unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR 75, shall not shall not exceed the applicable emission limitation, under 40 CFR 76.5, of 0.45 lb/mmBtu for tangentially fired boiler. If the unit is in compliance with its applicable emission limitation for each year of the plan, then the unit is not subject to the applicable limitation, under 40 CFR 76.7 (a)(1), of 0.40 lb/mmBtu until calendar year 2008. In addition to the described NO_x compliance plan, this unit shall comply with all other applicable requirements of 40 CFR 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions. In accordance with 40 CFR 72.40(b)(2), approval of the averaging plan shall be final only when all affected organizations have also approved this averaging plan.

* The number of allowances allocated to Phase II affected units by U. S. EPA may change under 40 CFR 73. In addition, the number of allowances actually held by an affected source in a unit may differ from the number allocated by U.S.EPA. Neither of the aforementioned condition does not necessitate a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR 72.84).

SECTION J – ACID RAIN (CONTINUED)

PERMIT (Conditions)

Plant Name: Louisville Gas and Electric Company	
Affected Units: 25- 30 (TC5-TC10)	

- **SO_2 Allowance Allocations and NO_x Requirements for the affected unit:**

SO_2 Allowances	**Year**				
	2003	2004	2005	2006	2007
Tables 2, 3 or 4 of 40 CFR 73	0*	0*	0*	0*	0*

NO_x Requirements	
NO_x Limits	N/A**

* For newly constructed units, there are no SO_2 allowances per USEPA Acid Rain Program

** These units currently do not have applicable NO_x limits set by 40 CFR, part 76**.**

SECTION J – ACID RAIN (CONTINUED)

PERMIT (Conditions)

Plant Name: Louisville Gas and Electric Company
Affected Units: 31 (Unit 2)

- **SO_2 Allowance Allocations and NO_x Requirements for the affected unit:**

SO_2 Allowances	**Year**				
	2005	2006	2007	2008	2009
Tables 2, 3 or 4 of 40 CFR 73	0*	0*	0*	0*	0*

NO_x Requirements	
NO_x Limits	N/A**

* For newly constructed units, there are no SO_2 allowances per USEPA Acid Rain Program

** This unit currently does not have applicable NO_x limits set by 40 CFR, part 76.

SECTION J – ACID RAIN (CONTINUED)

2. Comments, Notes, and Justifications:

1. Affected units are one (1) tangentially fired boiler and six combustion turbines, and one (1) supercritical PC boiler.

2. A revised Phase II NO_x Permit Application was received on June 12, 2001, including the existing unit.

3. All previously issued Acid Rain permits are hereby null and void

4. Nitrogen Oxide Compliance Plan for the facility remains unchanged since September 19, 1996.

5. Initial SO Compliance Plan was submitted with AR-96-007 application.

3. Permit Application: Attached

The Phase II Permit Application, and the Phase II NO_x Early Reduction Plan are part of this permit and the source must comply with the standard requirements and special provisions set forth in the Phase II Application, the revised Phase II NO_x Compliance Plan, and the revise Phase II NO_x Early Reduction Plan.

4. Summary of Actions:

Previous Actions:

1. Draft Phase II Permit (# AR-96-007) including SO_2 compliance was issued for public comments on September 19, 1996.

2. Final Phase II Permit (# AR-96-007) including SO_2 compliance plan was issued on December 19, 1996.

3. Draft Phase II Permit (# A-98-011) was advertised in the 1998 revised SO_2 allowance allocations and NO_x emissions standard for public comment on December 8, 1998.

4. Final Phase II Permit (# A-98-011) was issued with the 1998 revised SO_2 allowance allocations and NO_x emissions standards.

5. Draft Phase II Permit (# V-02-043) has been issued with the revised SO_2 allowance allocations and NO_x Early Reduction Plan. Draft permit relates to the Combustion turbines permitted in June 22, 2001.

6. Final Permit revised with the revised SO_2 allowance allocation and NO_x Early Reduction Plan.

Present Action:

1. Draft Revised Title V with Acid Rain Permit is being advertised for public comments.

SECTION K – NOx BUDGET PERMIT

1) Statement of Basis

Statutory and Regulatory Authorities: In accordance with KRS 224.10-100, the Kentucky Environmental and Public Protection Cabinet issues this permit pursuant to 401 KAR 52:020 Title V permits, 401 KAR 51:160, NO_x requirements for large utility and industrial boilers, and 40 CFR 97, Subpart C.

2) NO_x Budget Permit Application, Form DEP 7007EE

The NO_x Budget Permit application for these electrical generating units was submitted to the Division and received on May 27, 2005. Requirements contained in that application are hereby incorporated into and made part of this NO_x Budget Permit. Pursuant to 401 KAR 52:020, Section 3, the source shall operate in compliance with those requirements.

3) Comments, notes, justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements or conditions.

Affected units are one (1) Pulverized coal-fired, dry bottom, tangentially fired boiler, six (6) 150-megawatt simple cycle natural gas fired units and one (1) Supercritical Pulverized Coal (SPC) fired boiler. Each unit has a capacity to generate 25 megawatts or more of electricity, which is offered for sale. The units use coal and natural gas as fuel source, and are authorized as base load electric generating units.

4) Summary of Actions

The NO_x Budget Permit is being issued as part of this revised Title V permit for this source. Public, affected state, and U.S. EPA review will follow procedures specified in 401 KAR 52:100.

BabcockPower

Andover Technology Partners

Selective Catalytic Reduction System Performance and Reliability Review

James E. Staudt

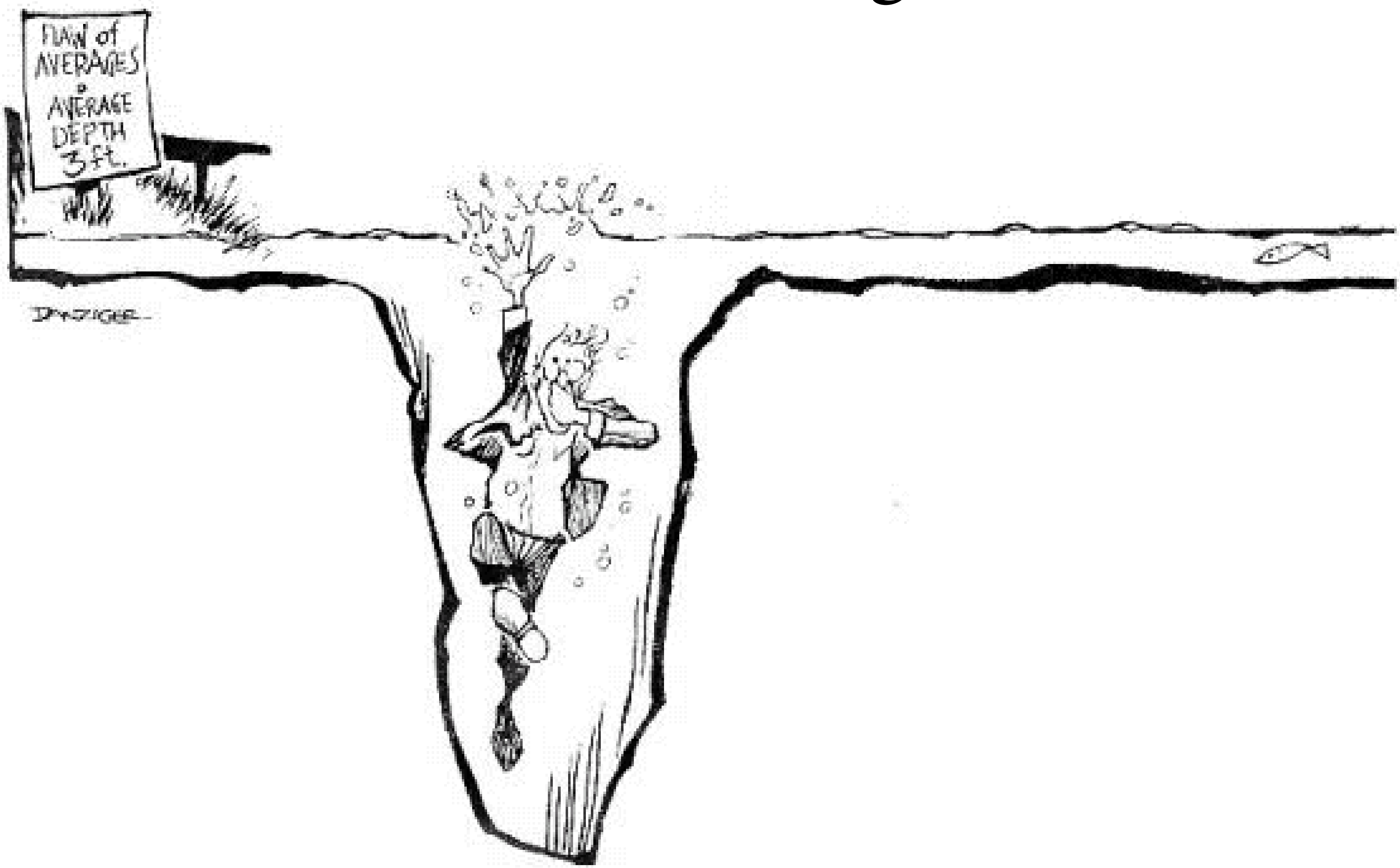
Andover Technology Partners

Clayton Erickson

Babcock Power Environmental Inc.

BabcockPower | Andover Technology Partners

Flaw of Averages



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Past Work

- Study One
  - Focused on ability to meet removal efficiency
  - Number of SCR systems analyzed small
- Study Two
  - Focused on removal efficiency
  - Considered operational choices
- Study Three
  - Analyzed more units
  - Investigated effect of system design and arrangement

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Current Work

- Investigated two parameters to measure reliability
  - Coefficient of Variation (CV)
  - Load Effect (LE)
- Evaluated data sets
  - 2005 hourly emissions less than 0.15 lb/MMBtu
  - 2005 hourly emissions on SCR equipped, Ozone and yearly
  - 2002 thru 2005 on select SCR systems

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Reliability Parameters

- Coefficient of Variation (CV)
  - Dimensionless number allows comparison of variation with different mean values
  - If CV greater than 100% indicates values standard deviation greater than average for data set
- Load Effect (LE)
  - Dimensionless number comparing average hourly emission to overall emission based on mass emitted
  - Measure of load effect on SCR ability to operate

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Emissions and Removal Efficiency

- All data obtained from EPA Electronic Data Reporting (EDR) website
- Ozone season emissions determined from may 1st to September 30th
- Removal efficiency calculated using 1st quarter emissions as uncontrolled based

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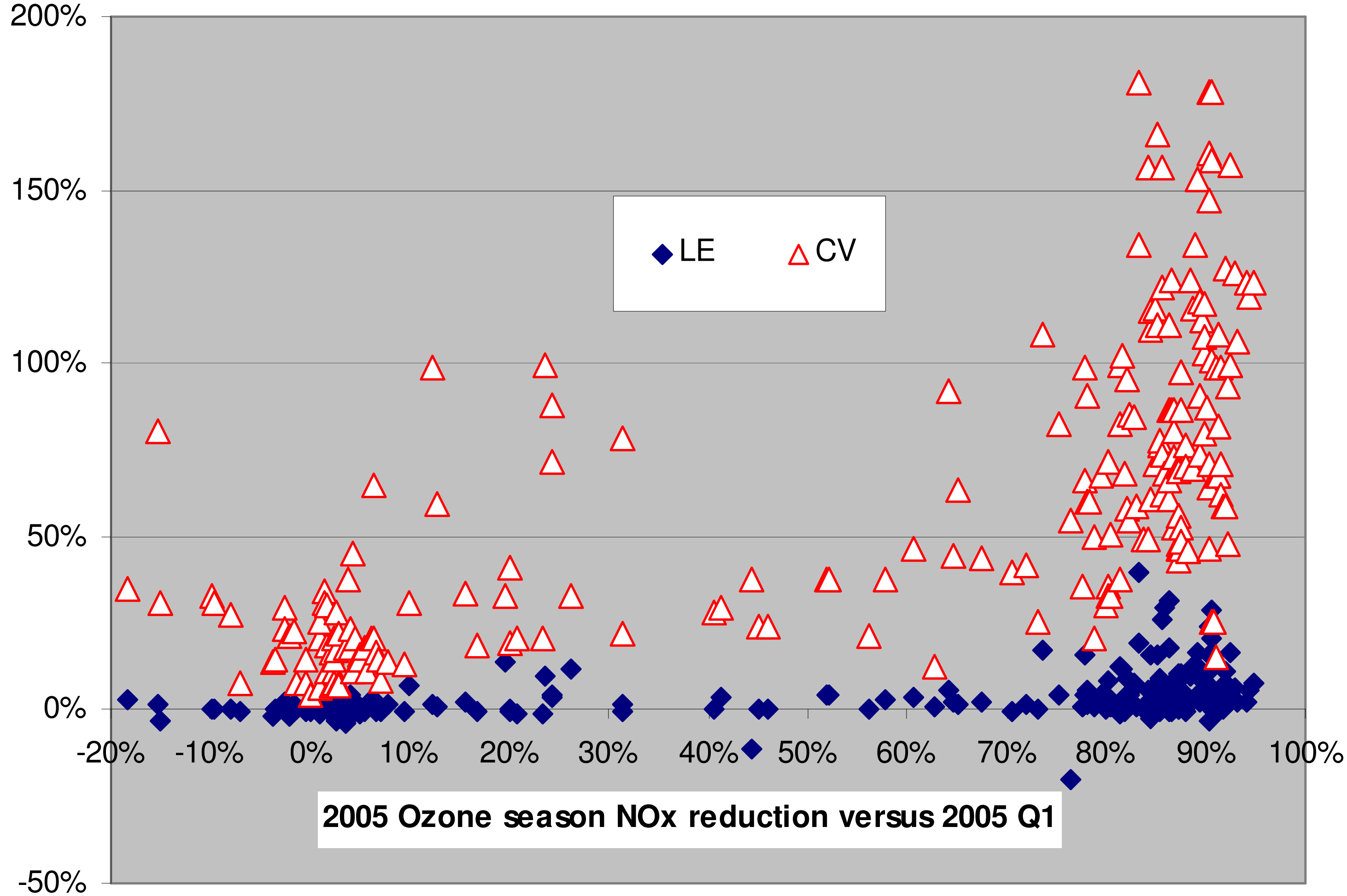
Units with NO_x Emissions Below 0.15 lb/MMBtu for 2005 Ozone Season



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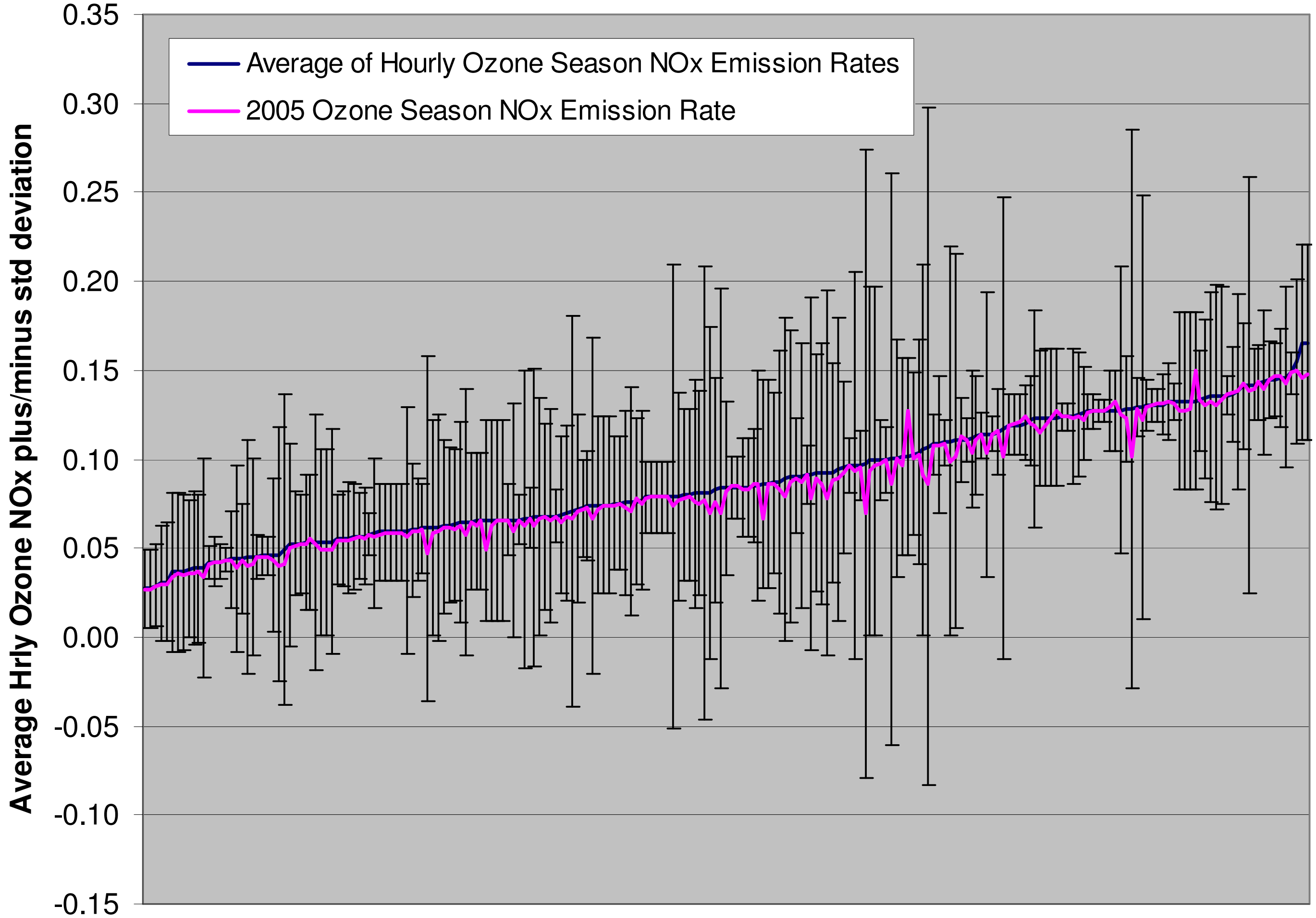
Units with NO_x Emissions Below 0.15 lb/MMBtu for 2005 Ozone Season



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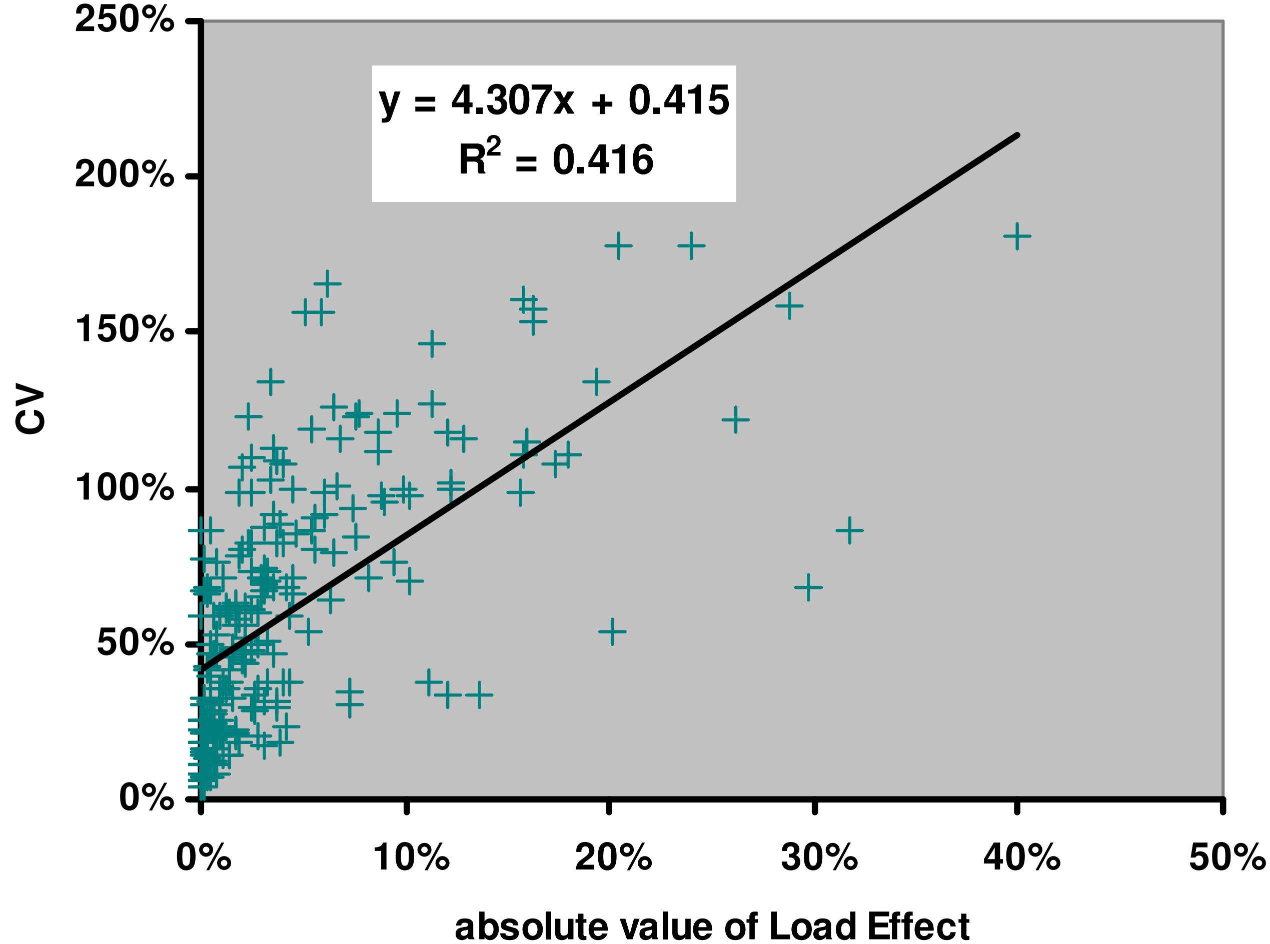
Units with NO_x Emissions Below 0.15 lb/MMBtu for 2005 Ozone Season



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Units with NO_x Emissions Below 0.15 lb/MMBtu for 2005 Ozone Season

- CV & LE correlation indicated some, not all, variation associated with load change
- May not be indicative of SCR reliability but how unit is requested to be operated
- Not all variation associated with load change, other factors resulting in variability

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2005 Ozone Performance for Units Equipped with SCR Systems

- Effect of bituminous vs. PRB coals
- Effect of catalyst type
- Effect of ammonia source
- Effect of year commissioned
- Comparison of 2004 to 2005 Ozone season operation

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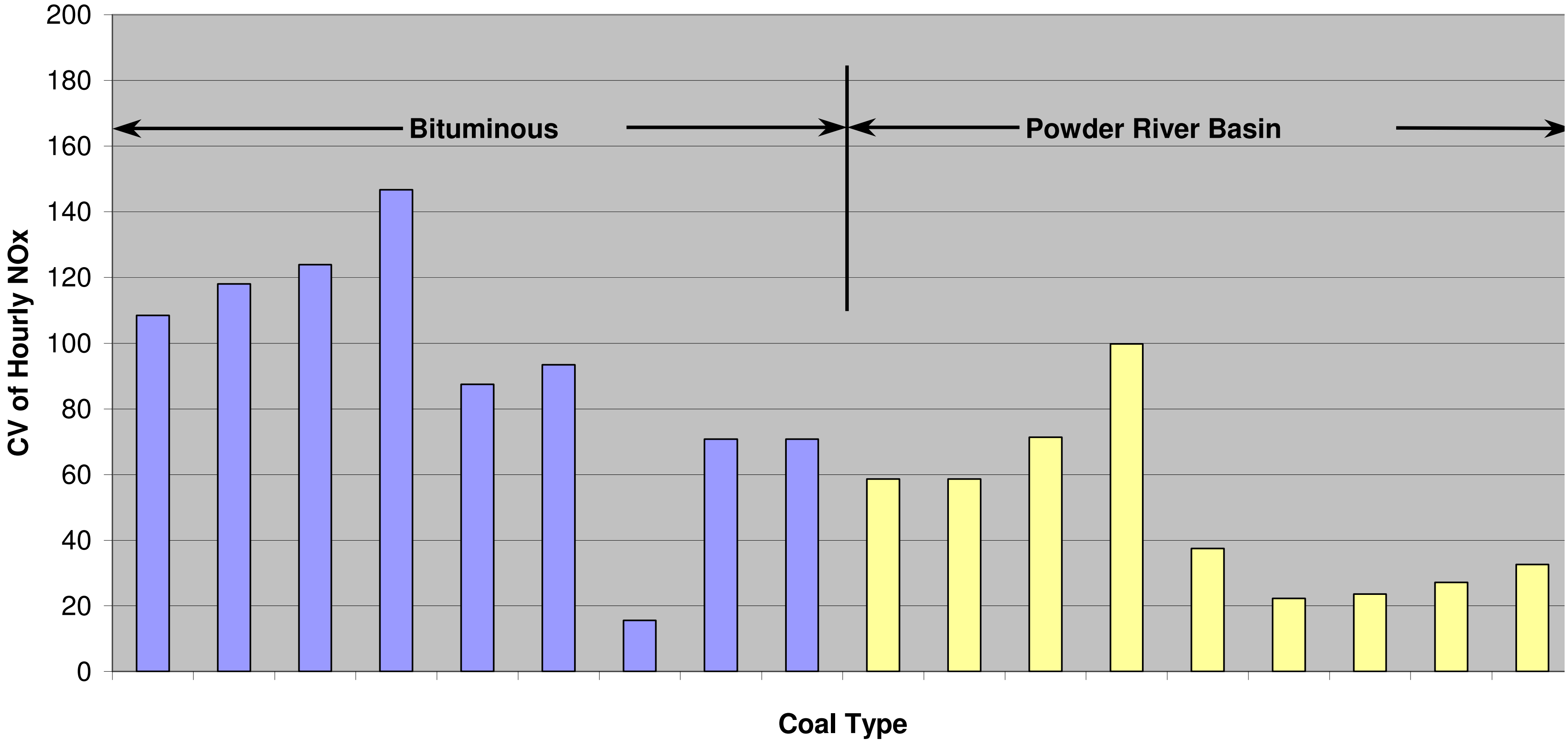
Effect of bituminous vs. PRB coals



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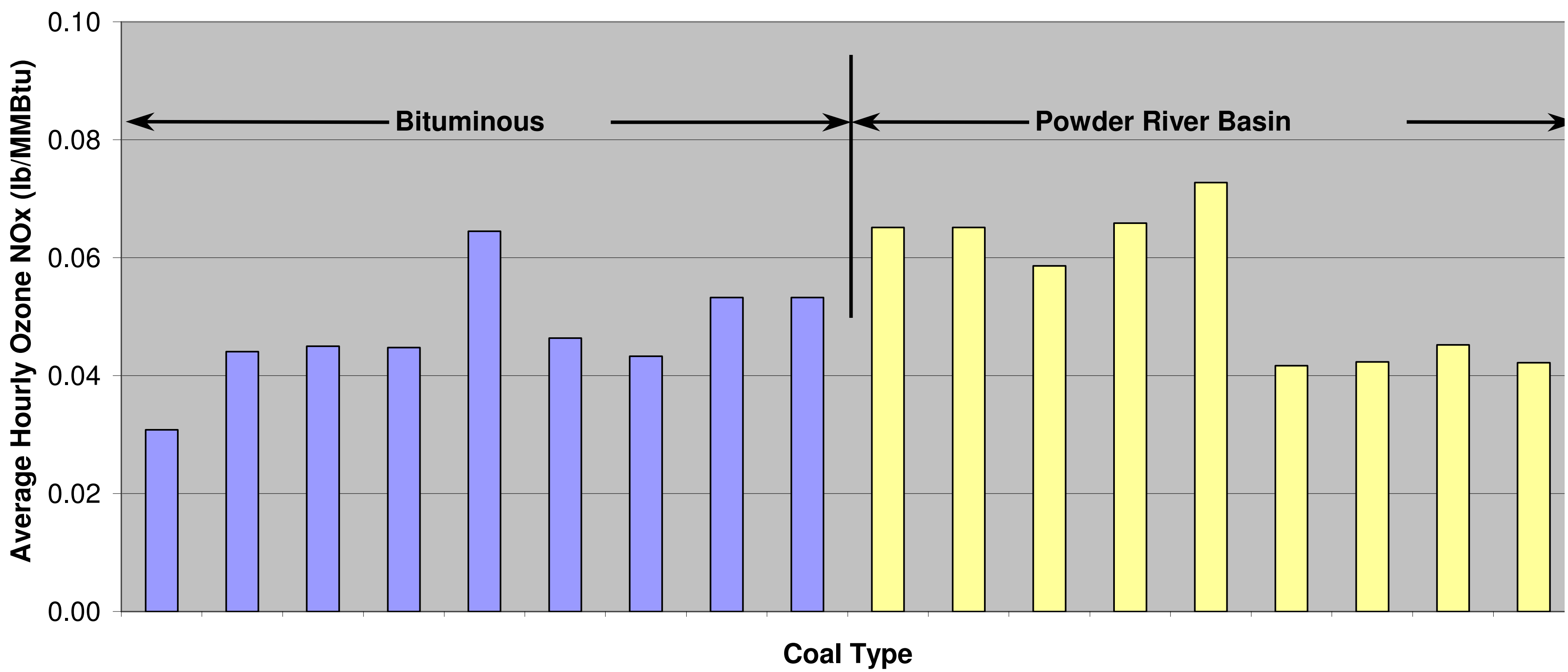
Effect of bituminous vs. PRB coals



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Effect of bituminous vs. PRB coals

- SCR systems on PRB fired unit have no greater control or reliability issues
- Bituminous SCR systems can attain same range of outlet NO_x as PRB
- Small data set for analysis
- Appears PRB units could operate with removals of bituminous resulting in lower outlet emissions

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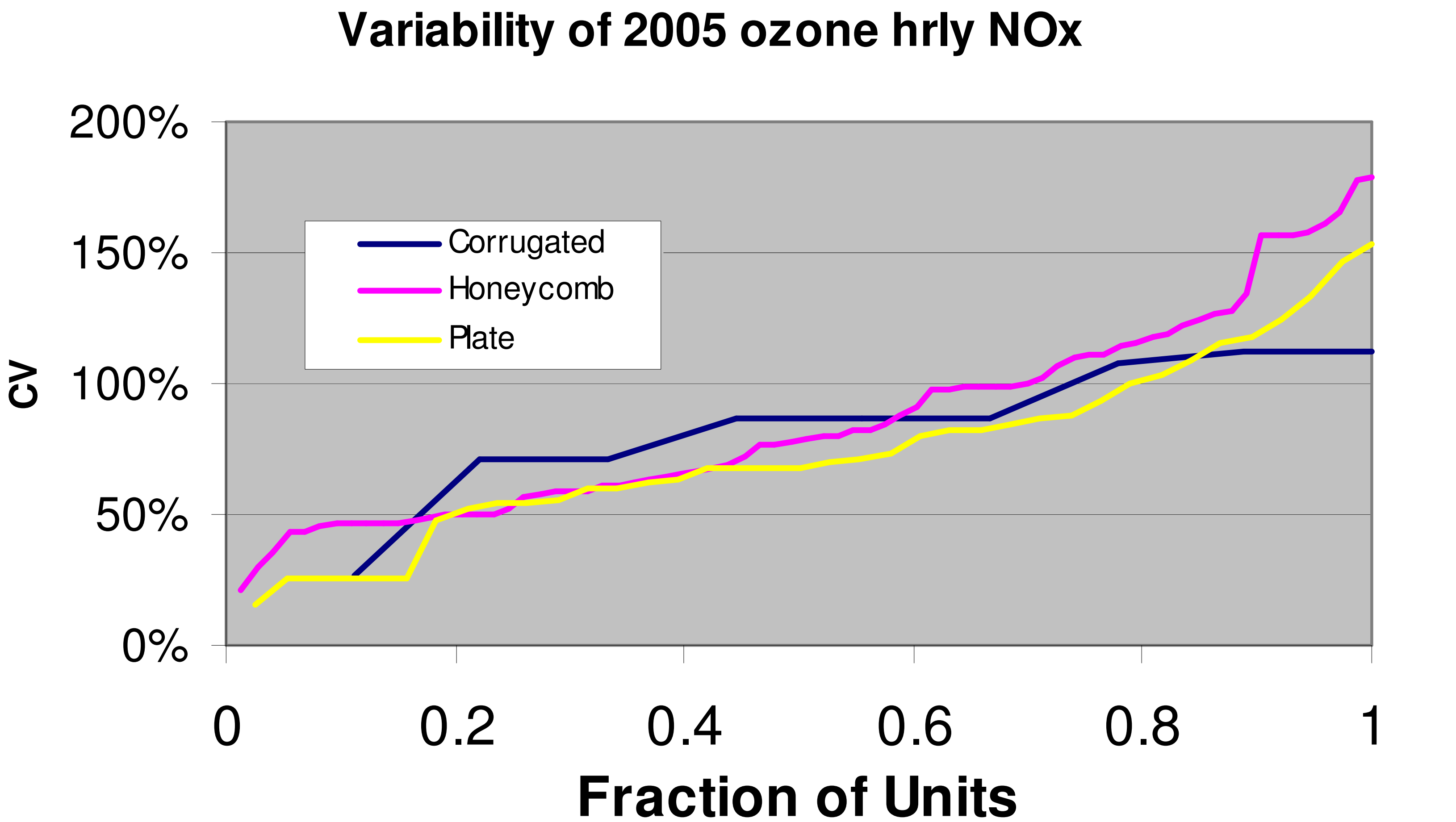
Effect of Catalyst Type



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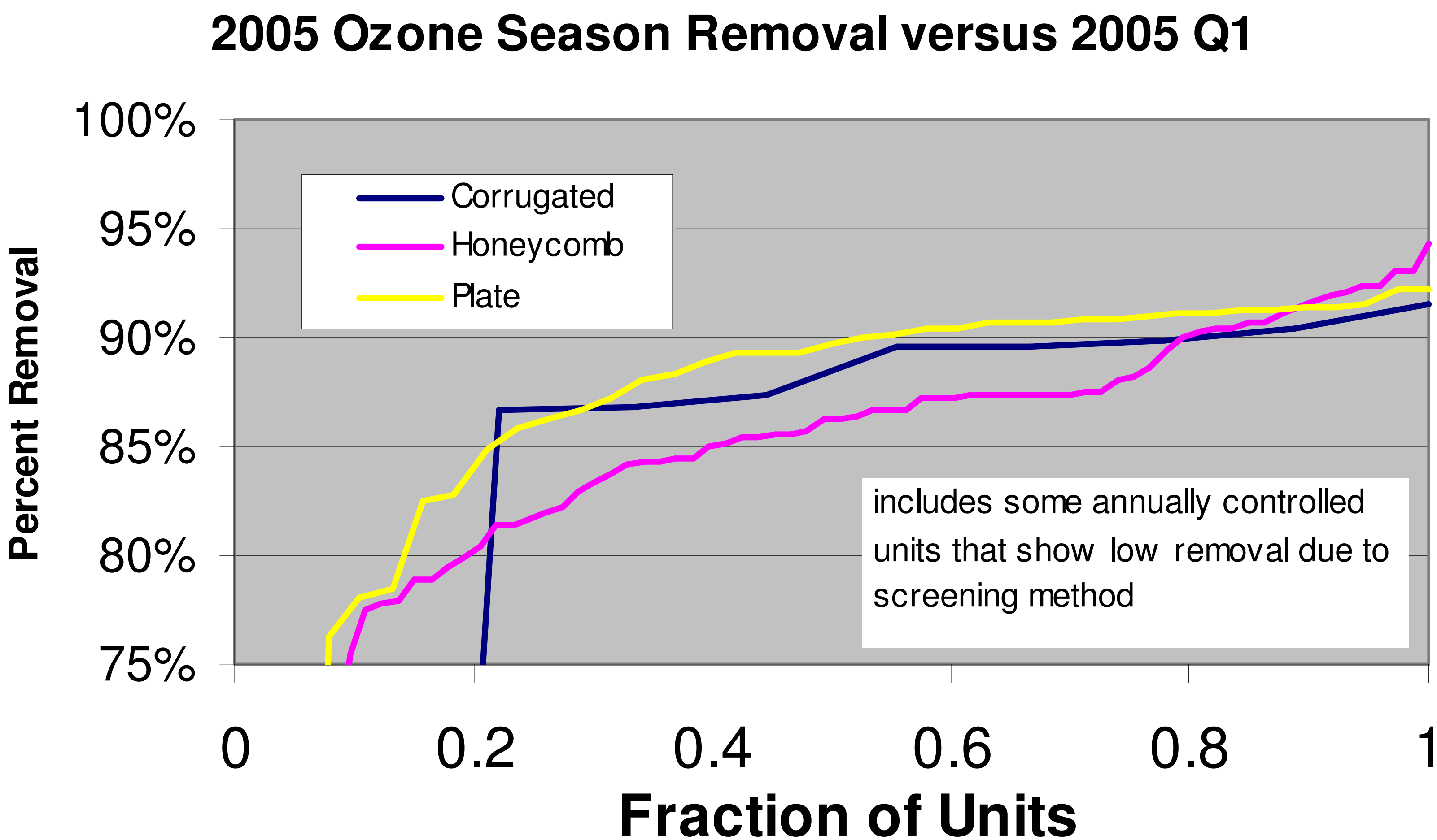
Effect of Catalyst Type



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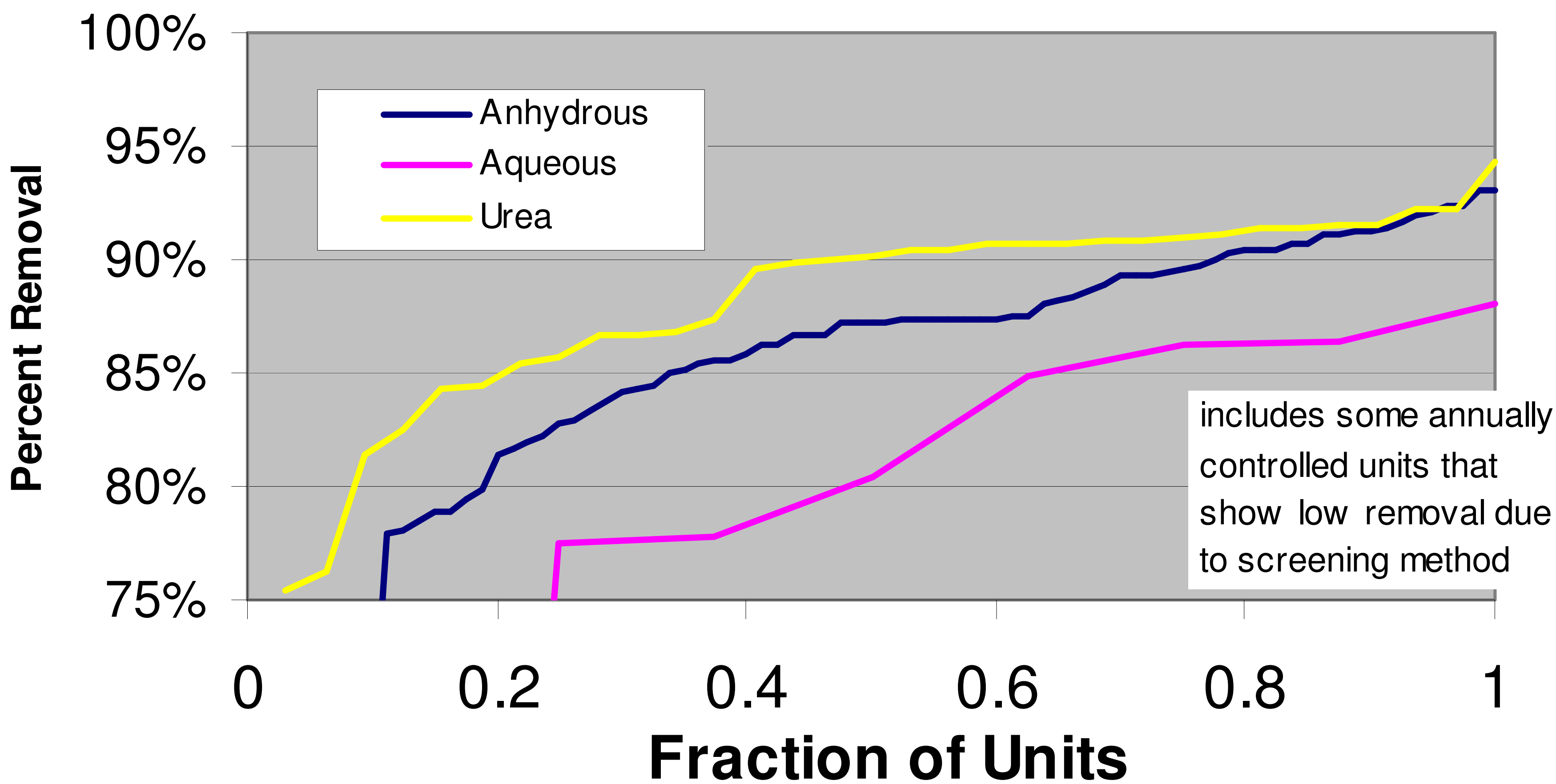
Effect of Ammonia Source

2005 Ozone Season Removal versus 2005 Q1



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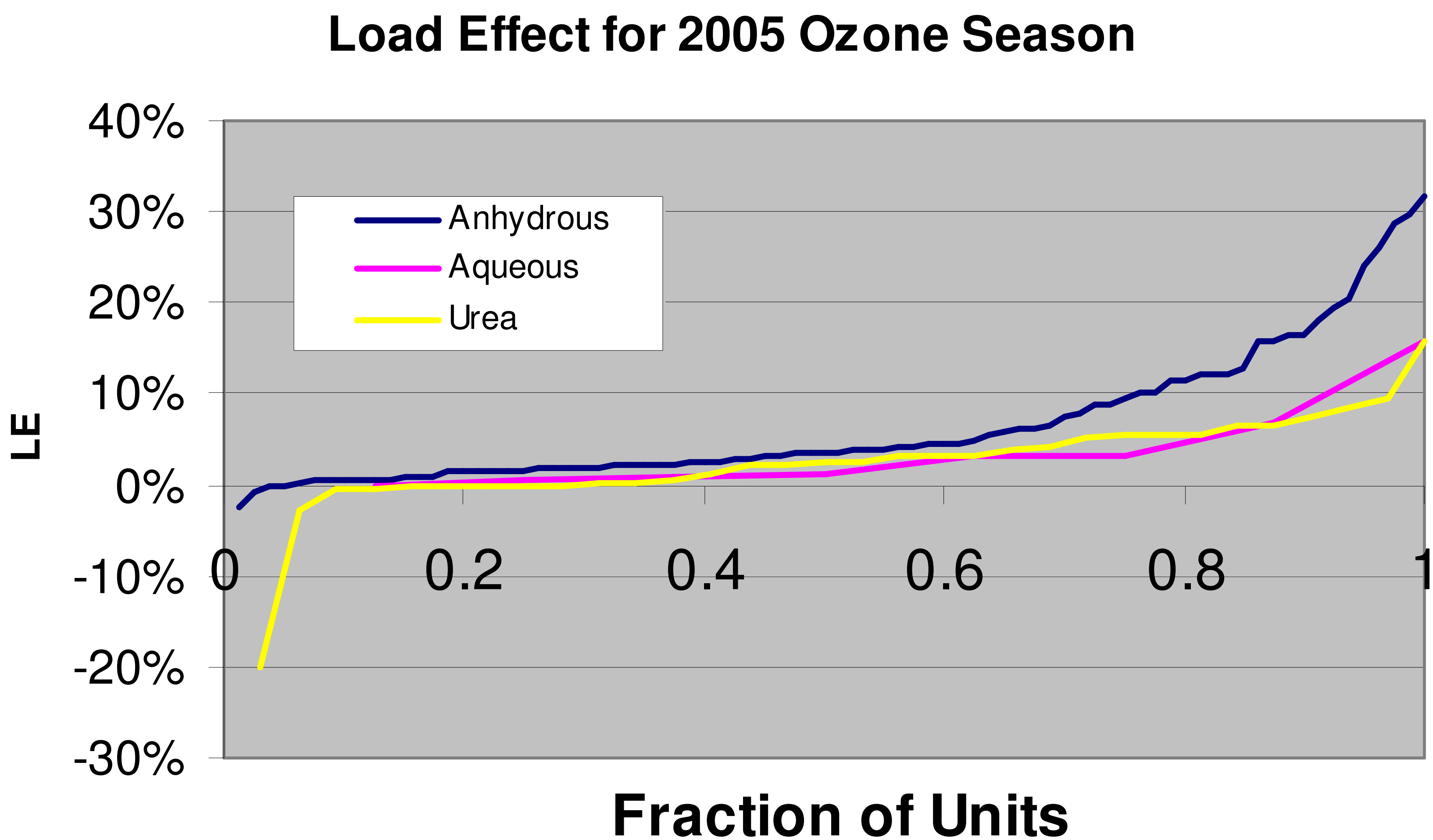
Effect of Ammonia Source



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Effect of Catalyst Type and Ammonia Source

- Catalyst type does not affect removal efficiencies, control variability or reliability
- System design and operation have greater influence than catalyst type
- Aqueous ammonia appears to affect removal efficiencies, no other affect found
- Ammonia source data set statistically small for aqueous, conclusion questionable

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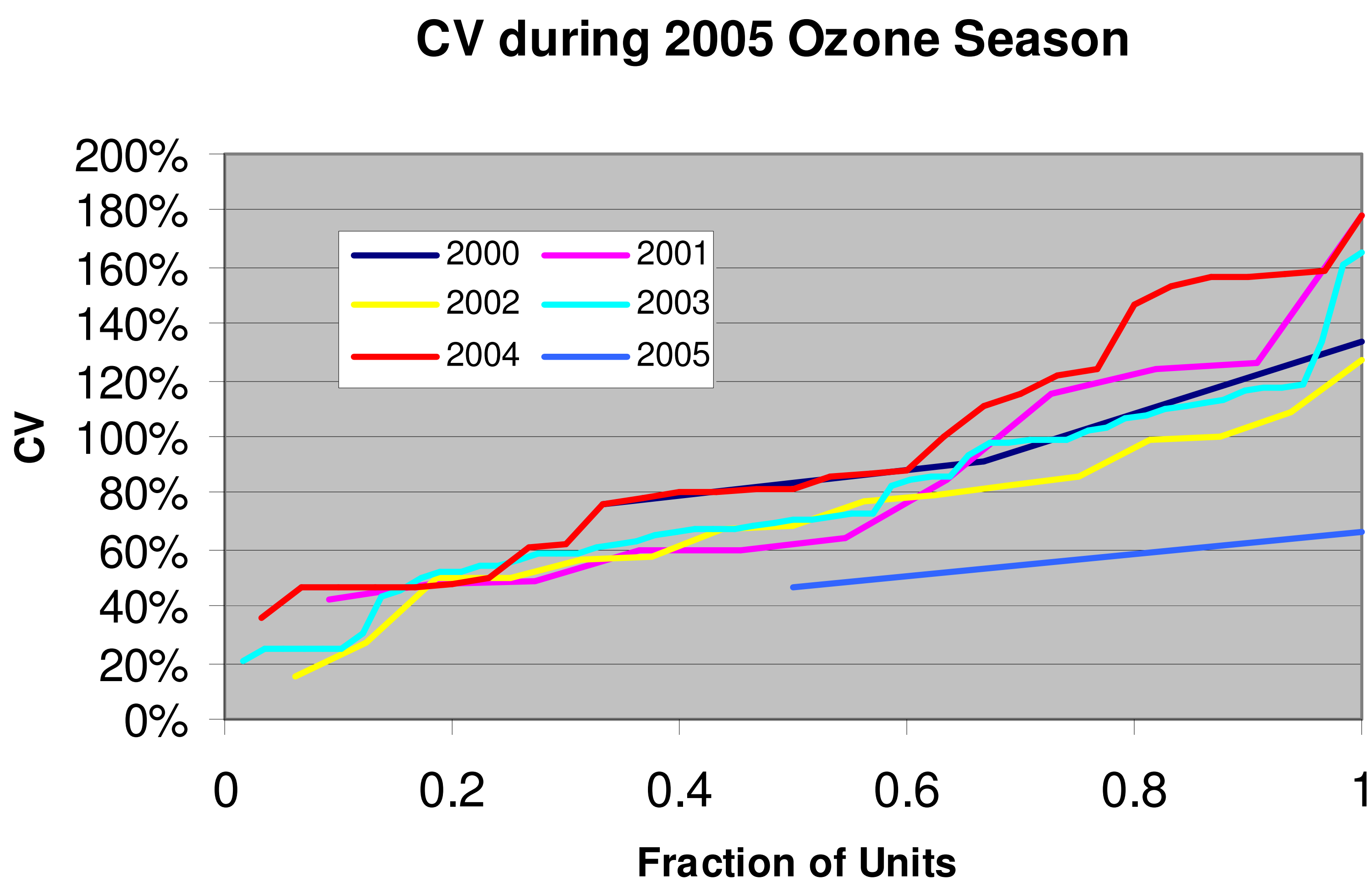
Effect of Year Commissioned



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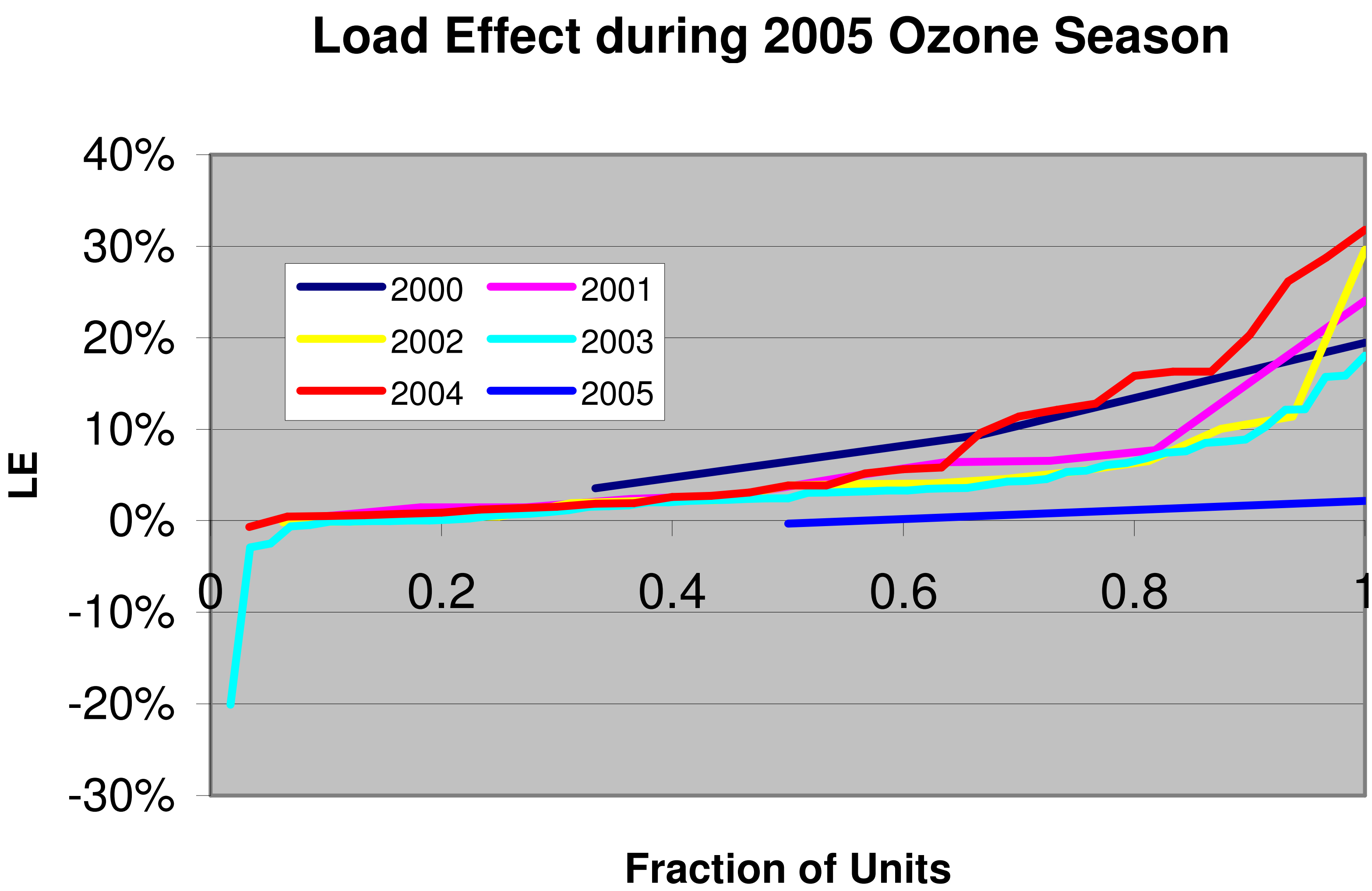
Effect of Year Commissioned



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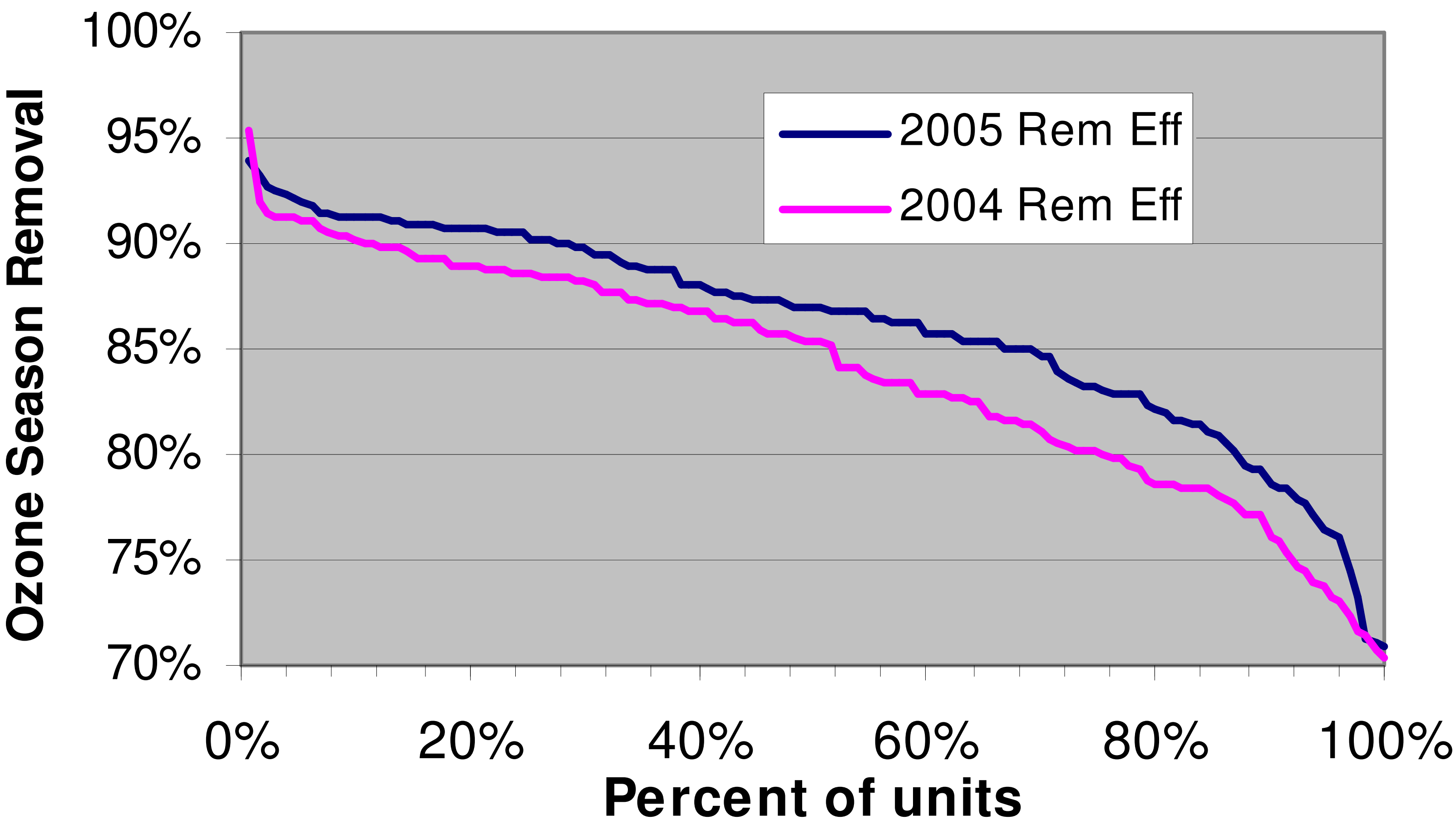
Comparison of 2004 vs. 2005 Ozone Season



Effect of Year Commissioned

- 2000 and 2005 data contains small number of units and is not considered
- Operator require at least one year to develop operating practices
- Most benefits learned in first year
- 2004 vs. 2005 marked increase (10% to 30% respectively) in units greater than 90% removal

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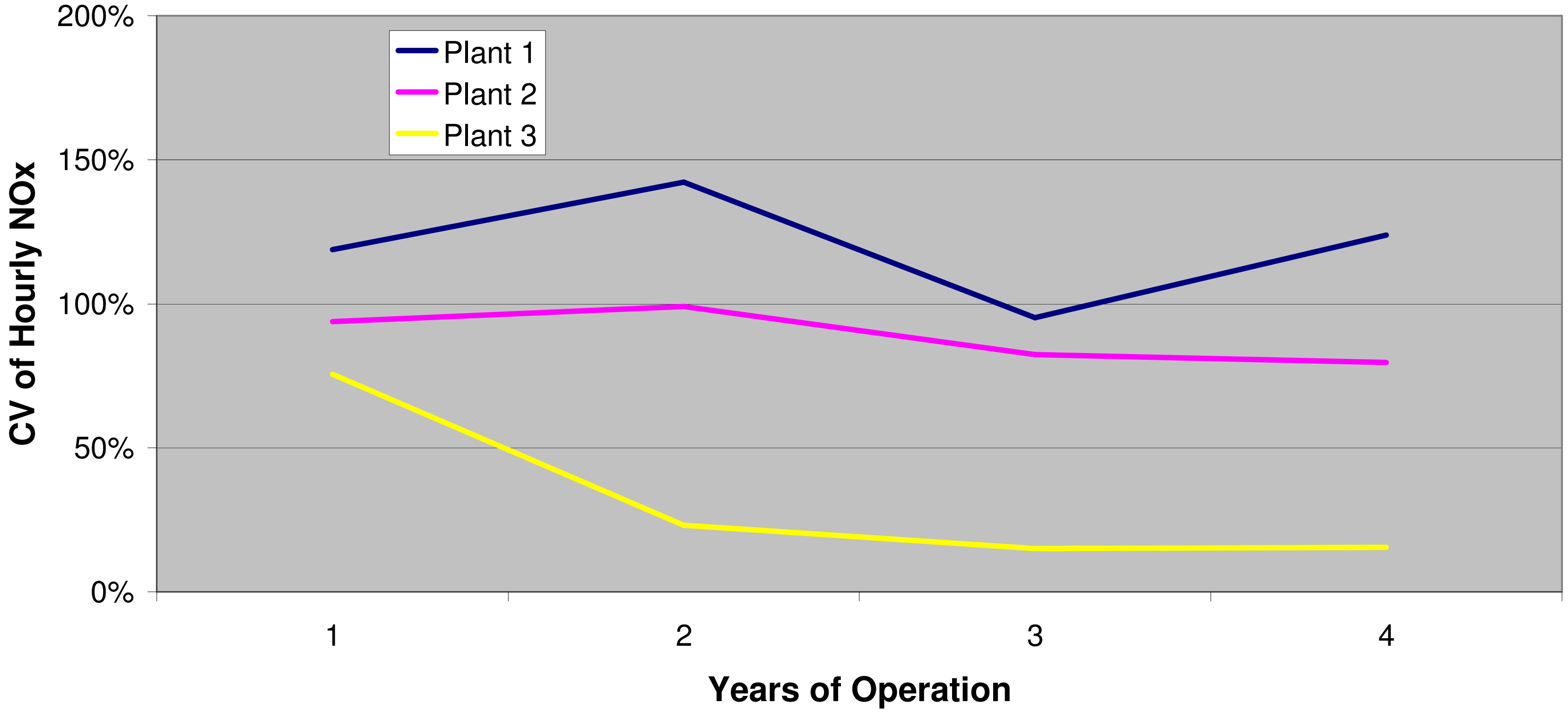
Operational Improvement and Stability Over Time



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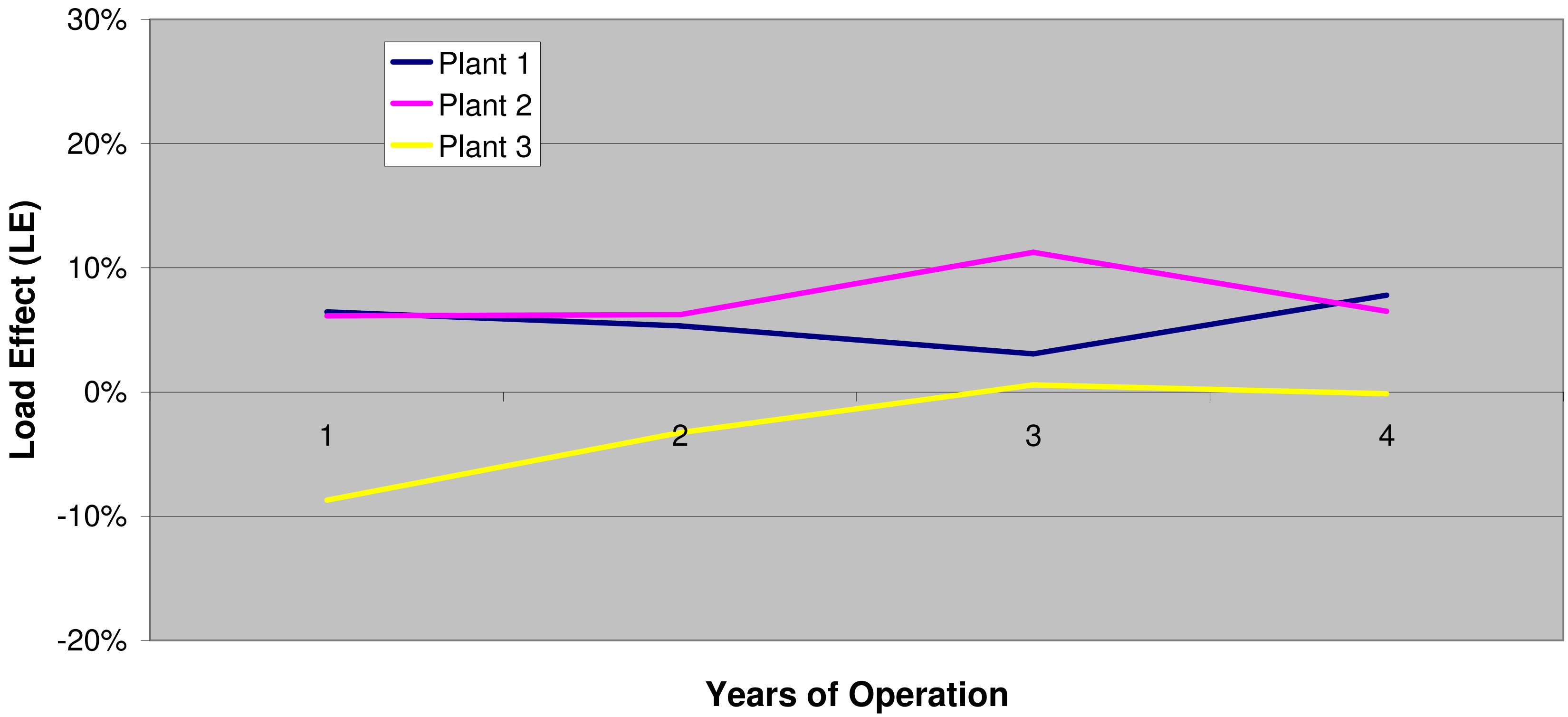
Operational Improvement and Stability Over Time



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Operational Improvement and Stability Over Time

- Three bituminous coal greater than 600 MW investigated
- Plant 1 uses anhydrous ammonia while Plant 2 and 3 use urea based ammonia
- Plant operations play major role even with same design and utility
- Certainty and number of conclusion limited based on available data set

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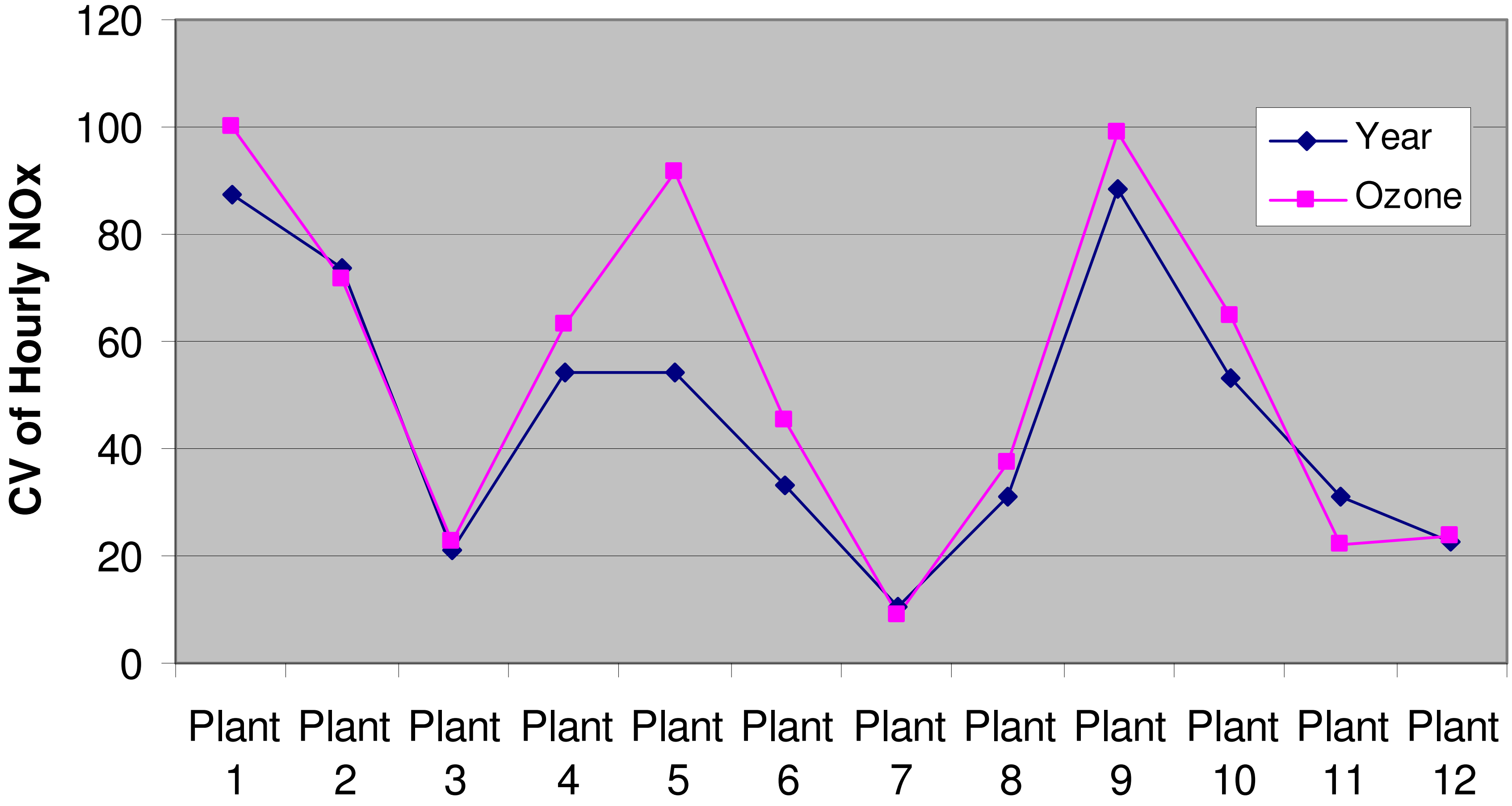
Comparison of Ozone vs. Year Round Operation



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Comparison of Ozone vs. Year Round Operation

- Plants 1 – 6 early SCR retrofits
- Plants 7 & 8 original Ozone units operated year round
- Plants 9 – 12 designed with boiler
- Low variability during year typically resulted in low for Ozone
- CV increases for Ozone season on almost all, possibly due to increase NO_x removal
- Considerable variation of CV between 12 plants

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Conclusions

- 90% NO_x removal being achieved by significant portion of US fleet
- High CV demonstrated for units with combustion only and SCR NO_x control equipment
- Units with highest CV not units with lowest absolute emission rates
- Outlet NO_x variability associated with operational practices
- Bituminous SCR units achieving similar outlet emissions rates

Conclusions

- Higher removal rates with PRB possible with current control variability
- Catalyst type shows not impact on NO_x removal or variability
- Ammonia source appears not to impact performance, incomplete data for aqueous ammonia
- Significant learning occurring across fleet resulting in increase in unit above 90% removal
- Ozone season variability greater than year round possibly do to increased removal efficiency

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Future Areas of Interest

- Determine other measurable SCR performance and reliability attributes
- Attempt to access plant by plant difference that affect performance
- Investigate method of determining affect of plant operations on performance

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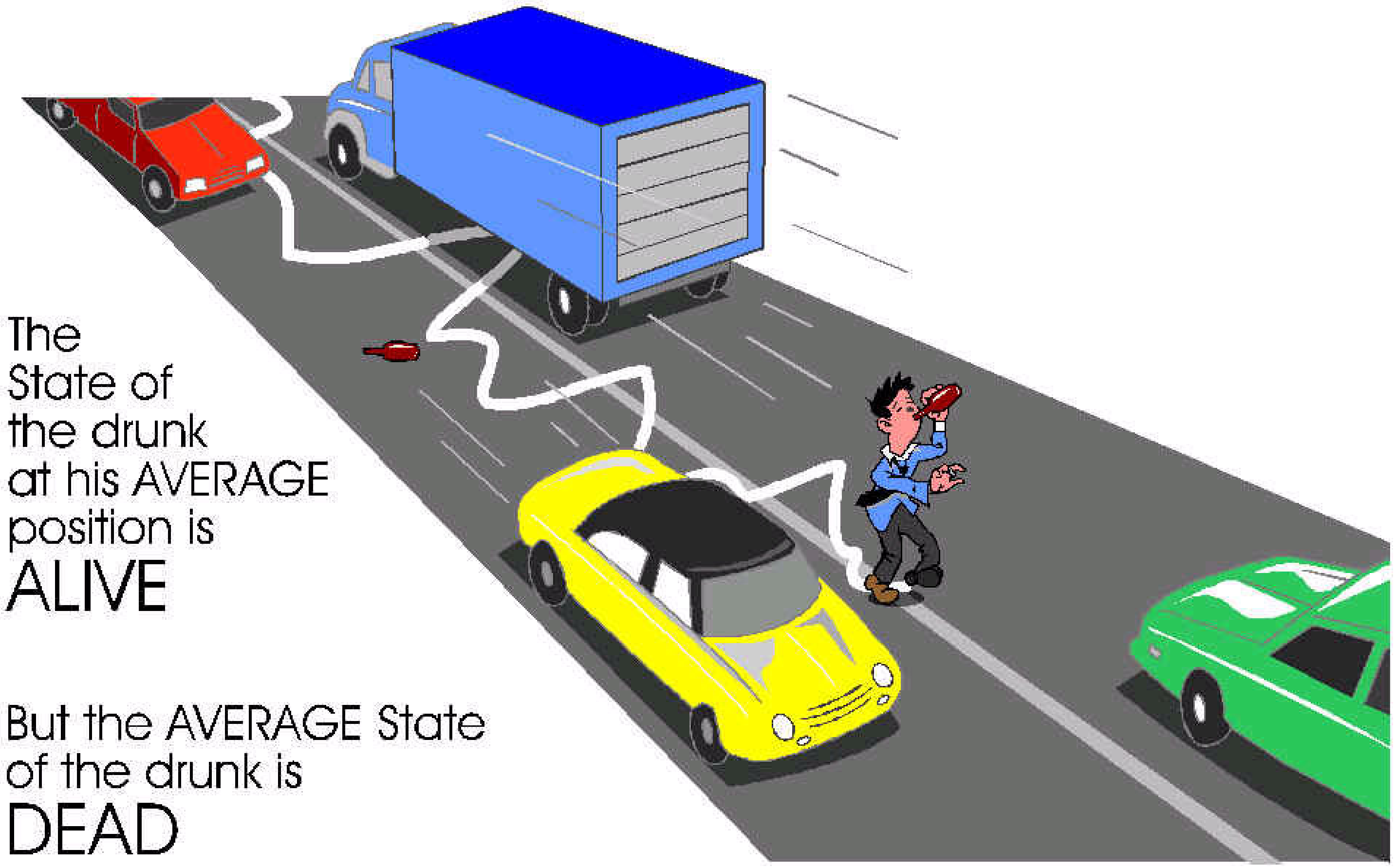
Questions



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]

[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.

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[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.
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> 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

[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, "<u>[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</u>."[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 production process or available methods, systems, and techniques, 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] In re: Maui Electric Company, PSD Appeal No. 98-2 (EAB September 10, 1998), at 29-30 (quoting NSR Manual at B.17).

[42] In re: Knauf Fiber Glass, PSD Appeal Nos. 98-3 – 98-20 (EAB February 4, 1999), at 12-13 (quoting NSR Manual at B.5) (emphasis added by EAB); see also In re: Steel Dynamics, Inc., PSD Appeal Nos. 99-4 and 99-5 (EAB June 22, 2000), at 29 n.24 (citing Knauf 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."); id. at B.6 (emphasizing that a proper Step 1 list is "comprehensive").

[43] In re: Spokane Regional Waste-to-Energy Applicant, PSD Appeal No. 88-12 (EPA June 9, 1989), at 9) (internal quotation marks omitted) (emphasis in original); see also In re: Inter-Power of New York, Inc. 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."); In the Matter of Pennsauken County, New Jersey Resource Recovery Facility, 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-

[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

[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

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[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.
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> 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]

[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

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[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

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[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.

[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**
SO2	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	.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
H2SO4			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.

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

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):

Table 4

	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.

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[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

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[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

[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.

Lower SO_2 Emission Limits Are Achievable

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).

The PSD Permit Must Also Specify a SO_2 Control Efficiency Requirement

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.

The PM and Total PM_{10} BACT Analyses Are Flawed

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

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[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

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[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), all 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.

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[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 8.64×10^{-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 42×10^{-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

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[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

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

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.

[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.

[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 49.7$\mu g/m^3$ and the second high 24-hour SO_2 concentration was predicted to be 8.9 $\mu g/m^3$, both well in excess of the 3-hour SO_2 Class I increment of 25 $\mu g/m^3$ and the 24-hour Class I increment of 5 $\mu g/m^3$. 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 $\mu g/m^3$ and the second high 24-hour SO_2 concentration was predicted to be 8.5284 $\mu g/m^3$. *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.

<u>Sithe Failed to Model Maximum Short Term Average SO_2 Emissions as Reflecting Current Actual Emissions.</u>

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 "99^{th} 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

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[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]

[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

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[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,

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Coal-Related Greenhouse Gas Management Issues
May 2003

THE NATIONAL COAL COUNCIL

Coal-Related Greenhouse Gas Management Issues
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Chair: J. Brett Harvey
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The National Coal Council
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U.S. DEPARTMENT OF ENERGY

Spencer Abraham, U.S. Secretary of Energy

The National Coal Council is a Federal Advisory Committee to the Secretary of Energy. The sole purpose of the National Coal Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to coal or to the coal industry.

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PREFACE

The National Coal Council is a private, nonprofit advisory body, chartered under the Federal Advisory Committee Act.

The mission of the Council is purely advisory: to provide guidance and recommendations as requested by the U.S. Secretary of Energy on general policy matters relating to coal. The National Coal Council is forbidden by law from engaging in lobbying or other such activities. The National Coal Council receives no funds or financial assistance from the Federal Government. It relies solely on the voluntary contributions of members to support its activities.

The members of the National Coal Council are appointed by the Secretary of Energy for their knowledge, expertise and stature in their respective fields of endeavor. They reflect a wide geographic area of the U.S. and a broad spectrum of diverse interests from business, industry and other groups, such as:

- Large and small coal producers;
- Coal users such as electric utilities and industrial users;
- Rail, waterways, and trucking industries as well as port authorities;
- Academia;
- Research organizations;
- Industrial equipment manufacturers;
- State government, including governors, lieutenant governors, legislators, and public utility commissioners;
- Consumer groups, including special women's organizations;
- Consultants from scientific, technical, general business, and financial specialty areas;
- Attorneys;
- State and regional special interest groups; and
- Native American tribes.

The National Coal Council provides advice to the Secretary of Energy in the form of reports on subjects requested by the Secretary and at no cost to the Federal Government.

ABBREVIATIONS

AEO	Annual Energy Outlook
AFBC	Atmospheric fluidized bed combustion
AMM	Abandoned mine methane
API	American Petroleum Institute
BACT	Best available control technology
Bcf	Billion cubic feet
Btu	British thermal units
Btu/kWh	British thermal units per kilowatt-hour
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
CBM	Coalbed methane
CCS	CO_2 capture and storage
CCT	Clean Coal Technology
CDM	Clean Development Mechanism
CFB	Circulating fluidized bed
CMM	Coal mine methane
CO	Carbon monoxide
CO_2	Carbon dioxide
COE	Cost of electricity
DOE	Department of Energy
DSM	Demand side management
EEI	Edison Electric Institute
EIA	Energy Information Administration
EIIP	Emission Inventory Improvement Program
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FBC	Fluidized bed combustor
FE	Fossil energy
FGD	Flue gas desulfurization
FY	Fiscal year
GCCI	Global Climate Change Initiative
GDP	Gross domestic product
GHG	Greenhouse gas
GW	Gigawatts
GWP	Global warming potential
H_2	Hydrogen
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
JI	Joint implementation
kW	Kilowatt
kWh	Kilowatt-hour
lb/MBtu	Pounds of emissions per million Btu of heat input
lb/MWh	Pounds of emissions per megawatt-hour generated
LHV	Lower heating value
LNB	Low NO_x burners
MBtu	Million Btu
MMTCE	Million metric tons carbon

$MTCO_2$	Million tons of carbon dioxide
MW	Megawatts
MWh	Megawatt-hour
N_2O	Nitrous oxide
NCC	National Coal Council
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NMA	National Mining Association
NO_x	Nitrogen oxides
NSR	New Source Review
O&M	Operating and maintenance
PC	Pulverized coal
PFBC	Pressurized fluidized bed combustion
PFBCwTC	Pressurized fluidized bed combustion with topping combustor
PPM	Parts per million
PSI	Pounds per square inch
R&D	Research and development
RD&D	Research, development and deployment
SC	Supercritical
SCR	Selective catalytic reduction
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
TPY	Tons per year
UNFCCC	United Nations Framework Convention on Climate Change
USC	Ultrasupercritical
VAC	Ventilation air methane
WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute

SECTION 1:
EXECUTIVE SUMMARY

Purpose

By letter dated September 24, 2002 (see Appendix F), U.S. Secretary of Energy Spencer Abraham requested that the National Coal Council prepare a study of how increased energy efficiency and carbon sequestration can be utilized as part of a greenhouse gas (GHG) management program. The Secretary asked the Council to use as a starting point for this report its previous report, entitled "Research and Development Needs for the Sequestration of Carbon Dioxide as Part of a Carbon Management Strategy" as it was submitted to then-Secretary of Energy Bill Richardson in May 2000.

Secretary Abraham specifically asked that the Council evaluate the effectiveness and economics of sequestering carbon. He asked that the Council highlight the public-private partnerships already established between the U.S. Department of Energy and industry that currently address the issues of increasing electricity generation efficiency and carbon sequestration. Secretary Abraham also requested that the Council recommend ways that additional such partnerships could be established. Lastly, he asked the Council for its perspective on how voluntary approaches to reduce greenhouse gas emissions could best be achieved.

The Secretary expressed his hope that this report "will serve as a carbon management blueprint for industry and act as a catalyst to promote additional public-private partnerships to support voluntary reduction of greenhouse gases and carbon sequestration."

The Council accepted the Secretary's request and formed a study group of experts to conduct the work and draft a report. The list of participants of this study group can be found in Appendix E of this report.

Introduction

This report updates and expands on the findings and recommendations concerning greenhouse gas management by coal-related industries made by the NCC to the Secretary of Energy in May 2000. It should be read in conjunction with that earlier report, which provides a good overview of the political, environmental and economic factors framing the greenhouse gas issue, and a detailed discussion of various carbon sequestration options. In this report, we have built on the findings of the earlier report, incorporating new information gathered over the last three years and analyzing in more detail the opportunities, needs and impediments to the development and deployment of technology to reduce greenhouse gas emissions from coal-based industries.

Findings

Status of Current Programs for Voluntary Action

There has been widespread participation across a range of industries in voluntary programs to reduce greenhouse gas emissions. As described below, the number of participants and reported projects in the Voluntary Reporting of Greenhouse Gases Program ("1605b Reporting") has grown steadily since the program's inception a decade ago, and a wide variety of emissions reduction and sequestration projects have been reported.

In February 2003, the Bush Administration's Climate VISION program drew responses from essentially all of the major energy-intensive industrial sectors, which put forward specific action plans to meet the goal of reducing greenhouse gas emissions intensity by 18% in the next decade. The various public-private partnership programs, such as Climate Wise, the Landfill and Coalbed Methane Outreach, and the Green Lights programs, have drawn formal commitments to reduce future emissions from 85 entities.

This significant response of U.S. businesses to calls for voluntary action demonstrates that they view global climate change as an important issue. Companies are taking steps to identify not only the risks and challenges associated with the evolving climate change arena, but also the business opportunities that could be developed. To do this, however, companies must first have an understanding of the extent and nature of their GHG emissions. In that regard, all of the voluntary action programs should benefit from the current work underway in the Department of Energy to provide improved guidelines for reporting GHG emissions and reductions under the 1605b program. It is important that changes to the 1605b program are consistent with accounting and reporting principles supported by U.S. industry, and, to the extent possible, harmonized with international accounting and reporting protocols.

To some extent, greenhouse gas reductions through voluntary actions have been inhibited by certain regulatory impediments. That is, environmental regulations can be a disincentive for businesses to take actions to sequester or control greenhouse gas emissions. Two examples are cited in this report: reclamation requirements that inhibit more productive forestation practices on mined lands, and the implementation of New Source Review procedures that discourage power plant operators from making efficiency improvements.

Partnerships for Greenhouse Gas Management

The federal government has established or announced several programs to address the technical, environmental and societal challenges to widespread adoption of GHG management technologies by private industry, both domestically and internationally. Three of these programs, highlighted in this report, are the Regional Partnerships for Carbon Sequestration, the Climate VISION Program (see above), and the Carbon Sequestration Leadership Forum.

The Regional Partnerships program recognizes that opportunities for and impediments to large-scale carbon sequestration are likely to have a great deal of regional specificity. There will be differences in technical, economic and regulatory requirements depending on the type of sequestration sink and its location. The Regional Partnerships will address these issues through assessment projects during Phase I and field testing of promising options in Phase II.

Efforts also are under way to coordinate research and voluntary action on greenhouse gas management internationally. Since its climate change policy was announced, the Bush Administration has announced a number of bilateral international partnerships and other initiatives for international cooperation focused on collaborative efforts meant to address climate-related issues. Examples of opportunities for cooperation that may result in significant GHG reductions include, but are not limited to, CCT and CO_2 capture and storage technology development, expanded use of cogeneration and renewable sources of energy, as well as concrete ways of reducing GHG emissions through sustainable agriculture and forestry management practices.

On February 27, 2003, the Departments of State and Energy announced the formation of the Carbon Sequestration Leadership Forum, a ministerial-level international organizational focusing on enhancing international opportunities to address GHG management. The partnership will promote coordinated research and development with international partners and private industry, including data gathering, information exchange, and collaborative projects.

Efficiency in Electricity Generation

Efficiency improvement in electricity generation is a very important near-term option for reducing greenhouse gas emissions from coal-based power plants. Increased efficiency has several benefits. First, it can decrease the cost of electricity generation by reducing fuel consumption. Second, it can provide additional generating capacity at relatively low cost, without the need to site and build new plants. Third, it will, in most cases, reduce emissions of the criteria pollutants and the production of solid waste in proportion to the efficiency increase. Finally, it will decrease emissions of CO_2 in the same proportion.

In this report, we considered efficiency improvements that can be applied to the existing generating fleet, and those that can be achieved by the commercial deployment of advanced clean coal technologies in new facilities.

With respect to the existing fleet, 75% of existing plants are candidates for retrofit of technologies to increase boiler or steam turbine efficiency, and 25% could be retrofitted with a CCT. If these improvements all were implemented it would result in an overall efficiency increase of approximately 8%, with a proportional decrease in CO_2 emissions. In terms of emission reductions, this would be the equivalent of replacing or repowering 24 GW of existing coal-based generating capacity with “zero-emission” technology, with a corresponding CO_2 emission reduction of approximately 200 million tons annually.

As a result of the DOE-industry sponsored CCT Program, a number of new coal-based power generating systems of increased efficiency are now commercially available. Others will be available for demonstration and deployment after 2010. Four specific technologies are discussed in this report, either because of their readiness for application or significant promise of performance in the near future (with further development):

- Pulverized coal (PC) combustion with supercritical (SC) and ultra-supercritical (USC) steam;
- Pressurized Fluidized Bed (PFBC) Combined Cycle with Topping Combustor (PFBCwTC);
- Integrated Gasification Combined Cycle (IGCC); and
- Hybrid Gasification/Fuel Cell/GT/Steam (DOE’s Vision 21Cycle)

These technologies offer 45% cycle efficiency (LHV), leading to a potential for a 25% CO_2 emissions reduction, compared to installed capacity. United States and international R&D efforts are in progress to develop advanced materials for USC plants with the prospect of an efficiency increase up to 50% (LHV). Such plants are expected to be available for initial deployment by 2010.

At present, capital costs, operating costs and the cost of electricity are lower for PC-SC steam than for the combined cycles. However, PFBCwTC and, especially, IGCC could become more competitive if CO_2 sequestration were required, because of the lower potential cost for CO_2 capture with these advanced systems.

Vision 21 Cycle aims at "zero emissions" and >60% cycle efficiency. Development of this advanced power generation system is worthy of governmental and industrial support. It is the best prospect for extending coal use while meeting more stringent environmental limitations.

CO_2 Capture Technology

Analysis of the pathways to atmospheric CO_2 stabilization suggests that carbon capture and storage (i.e., sequestration) could ultimately account for more than 40% of global CO_2 emission reductions. However, this will require an extraordinary acceleration of current research programs, because there are no suitably developed technologies for capturing CO_2 at large sources, including coal-fired power plants, or for storing CO_2 in geologic or oceanic sinks. Capturing CO_2, in particular, poses large challenges in the areas of cost and energy consumption, and is generally considered to be a major economic impediment to the large-scale adoption of sequestration technology.

For conventional combustion-based plants, the partial pressure of CO_2 in the flue gas is only 2-3 psia. Of the five major types of processes being studied, the most developed is chemical absorption, which is commercial in the chemical and natural gas processing industries, although at a smaller scale than that required for power plants. A few power plant demonstrations using amine-based CO_2 removal systems are under way worldwide on relatively small generating units.

The chief drawbacks are large and expensive contacting and pumping equipment and the large amount of energy needed to desorb captured CO_2 and regenerate the sorbent. The total impact on a new supercritical unit would raise the cost of electricity (COE) by >60% and reduce net electrical output by about 30%. The impact of a retrofit to an existing subcritical unit would be even greater. Nonetheless, gaining experience operating pilot and full-scale systems at power plants is crucial to overall commercialization efforts, and these processes offer a solid basis for such testing as well as opportunities for cost and performance improvement.

Removing CO_2 from integrated gasification combined cycle (IGCC) plants is relatively easier. Gasifiers can be operated in a "steam shifted" mode to produce synthesis gas with a CO_2 partial pressure exceeding 150 psia. Of the five major types of process being explored, the most developed is physical absorption. According to a recent DOE-EPRI study for a 90% CO_2 reduction requirement at new power plants, an IGCC unit with CO_2 capture could have a COE 25% lower than that of a PC unit using monoethanol amine (MEA), assuming IGCC power block cost reduction goals are met. In absolute terms, however, the cost adders and energy penalties for IGCC CO_2 removal are high, and warrant further R&D.

Given the magnitude of the problem, research is needed on a wide range of new concepts, such as CO_2 clathrate (hydrate) separation, which offer promise for lower-cost CO_2 and H_2S removal. Given the time before wide-scale sequestration is likely to be practiced, there is an opportunity to explore a wide range of potential capture options, applicable to both gasification and combustion systems, in the hope that breakthrough technology can be identified to reduce the onerous costs and energy penalties of current approaches.

Carbon Sequestration

After CO_2 has been separated and captured from flue gas or syngas, it must either be stored or put to use. Several concepts for storage have been evaluated; however, options for carbon sequestration vary depending on the locations of storage sites and types of storage/ sequestration technologies used. The choice of sequestration option may also depend on the technology that generates the CO_2. For example, for combustion systems, it may be desirable to sequester CO_2 that contains other flue gas components, such as the acid gases. The capacity, effectiveness, and potential health and environmental impacts of various types of CO_2 storage systems and the potential impacts of inadvertent releases are key areas of scientific uncertainty. Leading approaches to CO_2 storage described in this report include:

- Geologic Sequestration
- Terrestrial Sequestration
- Ocean Sequestration
- Novel Sequestration Systems
- Novel Integrated Systems
- Utilization

Funding provided by the DOE and the private sector for carbon capture and sequestration research has increased considerably since the first National Coal Council report on this subject in May 2000. In FY 2000, the DOE carbon sequestration budget was around \$8 million. By FY 2003, this had been increased to \$42 million. As of October 2002, the DOE/FE portfolio included 104 projects, with a total value of \$162 million. Significantly, the non-federal cost share (\$66 million) represents 40% of the total, indicating willingness on the part of private industry to invest in this research, despite the uncertain need for and timing of its eventual application.

Demonstration of Capture and Sequestration Technology

One common need for all potential sequestration technologies is large-scale demonstration that is long enough to prove their technical and economic feasibility and to ensure that their CO_2 remains permanently in storage. Given the number of possible sinks and likely regional differences in the characteristics of these sinks, there is a need for a several of these large-scale, long-duration demonstrations.

As with any major new technology with enormous financial, environmental, and energy security ramifications, CO_2 sequestration technologies cannot be considered commercially ready until successfully proven at full-scale, under “real-world” conditions, for a period of time adequate to assure expectations of prolonged safety and reliability. Any demonstration needs to convince prospective public- and private-sector investors that the costs and risks are sufficiently understood and acceptable so as to enlist the commitment of manufacturers and service providers, financiers and insurers, state and local authorities, and the public. These demonstrations also must provide adequate scientific information on which to base future regulatory requirements related to the deployment of sequestration technology.

Given the diverse make-up of the coal-based generating fleet, the wide variation in the types and properties of regionally economical fuels for power production, and the tremendous range of terrestrial ecosystems and subsurface geological features found across the U.S., effective national deployment of carbon sequestration measures will require the development and commercialization of a portfolio of CO_2 capture and storage technologies.

In this regard, we note the Department's current call for proposals to create regional partnerships in the U.S. to identify sequestration options pertinent to specific geographic areas of the country, and to conduct feasibility and field studies of promising sequestration options. One outcome of this program should be a much clearer picture of the number of demonstrations that are necessary to qualify sinks of sufficient size to support large-scale sequestration (if it is required in the future).

To begin to populate a commercial sequestration technology portfolio over the medium-term (8-15 years), development and/or refinement of the most defined promising options and demonstration at pilot scale must begin immediately. Commercial success at full scale will require the effective integration of technologies for capturing CO_2 at power plants, safely transporting it to storage sites, and assuring that placed CO_2 will remain sequestered from the atmosphere for centuries. Therefore, addressing integration issues in conjunction with the pilot-scale demonstrations will accelerate their resolution at full scale.

Carbon Sequestration and the "Hydrogen Economy"

Just as coal plays a major role in the production of electricity, it has the potential to do the same for hydrogen. The added costs for CO_2 capture and storage will be significantly lower for hydrogen production than for electricity production. To the extent that gasification is the preferred route of producing hydrogen from coal, implementing gasification technologies will position coal to take advantage of this potential new market should a hydrogen economy evolve.

The recently announced Presidential FutureGen Sequestration and Hydrogen Research Initiative could well serve as a major platform for developing CO_2 sequestration in conjunction with coal gasification. This unique facility is envisioned to provide R&D capability to allow testing of novel equipment under realistic conditions and may carry a significant share of U.S. R&D activities. However, it will still be necessary to have multiple demonstrations or combinations of pilot and demonstration projects to cover differing gasification designs, or designs not based on gasification technology, with differing coals and differing regional types of sequestration.

Non-CO_2 Greenhouse Gases from Coal Production and Use

Carbon dioxide from coal combustion is the principal greenhouse gas emission associated with coal. However, two additional gases, methane and nitrous oxide, also are emitted during coal production and use. They may represent targets of opportunity for near-term reductions in greenhouse gas emissions.

Coal mine methane (CMM) is one of several major sources of anthropogenic methane, accounting for about 10% of anthropogenic methane emissions in the U.S. CMM is responsible for about 1% of the total GWP of U.S. anthropogenic emissions of all GHGs. The U.S. coal industry has made substantial progress in recovering and using CMM though drainage systems. Of the 134 Bcf of CMM liberated from underground mines in 2000, 36 Bcf was recovered and used. This recovery represents an almost three-fold increase from the 13.8 Bcf recovered in 1990.

Currently, the recovery of CMM is driven by two factors: the resulting improvement in mining conditions and the value of the gas. Most of the recovered CMM is used as pipeline-quality gas, although smaller quantities are used at qualities not meeting pipeline specifications and some is used as combustion air. Technologies under development -- including ultra-lean-burn turbines and methane concentration systems -- could expand the options available for recovery and use. Future GHG reduction requirements, in conjunction with advanced recovery technologies, could easily result in increased recovery or utilization of CMM.

N_2O has a GWP 296 times that of CO_2. Because of its long lifetime (about 120 years) it can reach the upper atmosphere, depleting the concentration of stratospheric ozone, an important filter of UV radiation. N_2O is emitted from fluidized bed coal combustion; global emissions from FBC units are 0.2 Mt/year, representing approximately 2% of total known sources. N_2O emissions from PC units are much lower. Typical N_2O emissions from FBC units are in the range of 40-70 ppm (at 3% O_2). This is significant because at 60 ppm, the N_2O emission from the FBC is equivalent to 1.8% CO_2, an increase of about 15% in CO_2 emissions for an FBC boiler. Several techniques have been proposed to control N_2O emissions from FBC boilers, but additional research is necessary to develop economically and commercially attractive systems.

<u>Assessing the Cost of Greenhouse Gas Management</u>
The cost of technological options to reduce, capture, and sequester CO_2 depends on a large number of factors. Different cost studies typically employ different assumptions that often are not fully communicated or well understood by their audience. Different assumptions can significantly influence cost results, and lead to large uncertainties that are frequently not reported. For technologies at pre-commercial stages of development, costs are especially uncertain. To the extent that cost estimates often are a factor in decisions about technology development or deployment, the basis for those estimates, and their uncertainties, needs to be better characterized in ongoing work.

Future GHG emission constraints would affect the price and availability of electricity — two factors that could have a profound impact on the U.S. economy. Because coal is abundant domestically, and its price is low and stable relative to other fossil fuels, the predominance of coal-based power plants has helped keep U.S. electricity affordable, reliable, and secure.
If stringent CO_2 reduction requirements are imposed, the cost of electricity and the balance in the fuel mix could change dramatically. CO_2 removal technologies would be unprecedented in their cost and energy consumption, compared to the emission controls for SO_2, NOx, and particulates adopted over the last 30 years. In the absence of commercially available CO_2 capture and sequestration technologies, substantial near-term (less than 10-12 years) CO_2 emission reduction requirements would likely force many coal-fired plants to be retired prematurely. This would likely lead to a further surge in the construction of new NGCC plants. Such a shift would place tremendous pressure on the gas production and pipeline industries to keep up with demand, and would tend to tie electricity prices ever more tightly to the price of natural gas, a fuel with a much more volatile price history than coal. While the historic price differential of gas to coal is

about 2:1, recent trends and availability projections may make that gap even greater in the future. Under this scenario, higher natural gas price prices would result in great impacts on the cost of electricity and on the economy in general.

Deployment of Greenhouse Gas Emission Reduction Technology

Implementing the technologies described in this report will require transitions both in the technology itself and in the policies and regulations that will govern the electricity generation business of the future. The need for orderly transitions is necessary due to the desire to minimize technical and financial risk on the parts of the generating companies and the financial institutions that will invest in new power plants.

It is likely that existing coal-fired plants will continue to provide the majority of our nation's electricity for decades to come, unless political decisions are made which force their retirement for economic reasons. Ultimately, economic and technical factors will make it necessary to build new power plants to replace retiring capacity and to meet load growth. As indicated in this report, significant reductions in CO_2 emissions can be achieved in the near term by increasing the efficiency of the existing generating fleet. Moreover, replacement or repowering of the existing units with new, more advanced CCTs can further increase fleet efficiency and reduce CO_2 emissions. Finally, new plants can be designed to facilitate CO_2 capture and sequestration, if this becomes necessary and technologically and economically feasible.

Three important components of federal policy in this regard are support of research and development, cost-sharing by the federal government in the first-of-a-kind demonstration of new technology, and tax incentives to encourage replicate deployment of demonstrated technologies. The latter is particularly important for encouraging investment in capital-intensive technologies such as central-station coal-fired power plants. The argument is that some number of these new technologies must be built to move the technology along a "learning curve" that reduces technical risk and cost to the point that plants can attract conventional commercial financing. This concept is embodied in the National Environmental and Energy Technology (NEET) legislation, which has been introduced in both the House and the Senate.

Timely advances in coal technology cannot be achieved without a significant increase in RD&D funding that will permit commercial viability within the next 10 years. This is problematic in the current economic and regulatory environment because power plant operators are under extreme pressure to reduce costs and are unwilling to invest in new technologies. Investing now in an advanced power plant technology requires patience, because the investment will not earn a return until some time after successful commercialization.

All of these issues suggest that traditional forms of private-sector funding for new technologies may not be feasible in today's electricity generation business environment. Public-private consortia are emerging as a mechanism to provide the needed resources for technology development. They allow for front-loading the R&D processes, as well as the early stages of pilot and full-scale tests. DOE funding of research for the advanced coal program follows this precept, in that the DOE cost share is higher for high-risk technology development and lower for commercialization activities. This approach has been a success in prior programs, such as the CCT Program, and it is working well to sustain interest in the current Vision 21 program. It is anticipated that it will be successful in the FutureGen program as well.

Although these programs encourage private-sector participation in the technology development process, the current funding levels are not adequate to develop and commercialize the technologies that the U.S. will need to deploy a new fleet of advanced coal-based generation systems.

Recommendations

Implementing Greenhouse Gas Management Technology

- The Department should continue to promote public-private partnerships, both domestically and internationally, to identify opportunities, incentives and regulatory impediments affecting voluntary actions to reduce GHG emissions, and to conduct research and technical assessments of carbon management technologies and opportunities.

- The Department should expedite revisions (as detailed in this report) to the National Energy Policy Act 1605b reporting guidelines for GHG emissions in a way that ensures they are sufficiently flexible to encourage voluntary action, and consistent with similar guidelines being developed by other public- and private-sector organizations.

- The Department should provide objective technical and economic information to inform public policy decisions and private investment decisions regarding GHG technologies. The Department also should work with other government agencies and the private sector to help develop and implement economic and other incentives (including removal of regulatory impediments) to accelerate the deployment of highly efficient advanced coal-based power technologies and other means of GHG emissions reduction. Early deployment of these advanced technologies is critical to reducing the cost of commercial application.

- The Department, working with other agencies as appropriate, should identify and assist in exploiting near-term opportunities for reductions of non-CO_2 GHGs associated with coal production and use, including emissions of methane and N_2O, and enhanced carbon management on mining lands.

- The Department should expand its cooperation with the Departments of State and Commerce in the areas of international research, development and demonstration for carbon management technologies as it has begun to do with the FutureGen Project. This cooperation should be conducted in concert with the domestic programs underway at DOE, in recognition of the global nature of GHG issues.

Developing Greenhouse Gas Management Technology

- The Department should continue to work closely with the private sector to improve and refine the technology “roadmap" for advanced coal-based power generation technology and carbon capture, transport and sequestration technology with particular attention to defining the time and cost necessary to achieve the roadmap's technical and economic goals.

- The Department should conduct and support R&D to improve the efficiency of coal-based power generation for both new and existing (or repowered) units as the most cost-effective and commercially available near-term means for reducing GHG and other emissions. This R&D includes:

- Materials for ultrasupercritical steam units capable of up to 50% LHV (47.5% HHV) cycle efficiency;
- Improvements in IGCC technology (syngas cleanup and gas turbine development) to enhance availability and reliability;
- Novel combustion processes capable of lower-cost CO_2 capture; and
- Development of the Vision 21 Fuel Cell Gas Turbine Hybrid to enable demonstration by 2010.

- The Department should expedite research on a wide range of CO_2 capture options applicable to either gasification or combustion technologies, to improve energy efficiency and reduce the cost of capture, and to explore promising novel technologies now in the laboratory or conceptual stage of development.

- The Department should continue and expand the core R&D and demonstration programs as described in the report. In addition, the Department should further develop the FutureGen project (including its associated goals for hydrogen and fuels production) as a research platform leading to technology demonstrations, while recognizing that the core R&D program is necessary to support not only FutureGen but a wider range of important coal technology.

- The Department should develop a set of guidelines regarding the key assumptions that should be reported when estimating the costs of CO_2 reduction technologies (including carbon capture and sequestration systems). These guidelines should include methods to characterize uncertainty in the reported results.

<u>Demonstrating Greenhouse Gas Management Technology</u>

- The Department should conduct a sufficient number of large-scale, long-term field tests of promising sequestration options to ensure that sinks of sufficient size and integrity are available to store the large volumes of CO_2 that would need to be sequestered if reductions were required. The tests are necessary to fully understand the technical, economic and environmental consequences of sequestration within the context of regional characteristics. The Department should begin them as soon as possible, because of the long time duration needed for adequate evaluation.

- The Department should support multiple, large-scale, integrated demonstrations combining the most promising generation, capture and sequestration technologies based on the development of the unit components and design studies of the integrated systems.

SECTION 2: EXISTING VOLUNTARY PROGRAMS AND PUBLIC-PRIVATE PARTNERSHIPS FOR GREENHOUSE GAS MANAGEMENT

2.1 Summary

This section outlines the recent voluntary actions by industry to reduce, avoid, sequester and control GHGs. The main emphasis will be on actions taken by coal producers and consumers, but other examples of voluntary actions by other entities are also presented. U.S. industry has been able to produce significant reductions in GHG emissions through a range of voluntary programs initiated in partnership with DOE. The success of these programs (and the lessons learned from them) have formed the bases for follow-on voluntary programs which will continue to provide GHG emission reductions in the future.

The main source for this information is the U.S. Energy Information Administration's (EIA) report, "Voluntary Reporting of Greenhouse Gases 2001." Values presented in this section are as reported by participants in this program for 2001.

2.2 Energy Policy Act of 1992 - Section 1605(b) Program

The Voluntary Reporting of Greenhouse Gases Program, established by Section 1605(b) of the Energy Policy Act of 1992, records the results of voluntary measures to reduce, avoid, or sequester GHG emissions. Since its inception in 1994, this program has received reports of over 2,000 projects to reduce or sequester GHG emissions. Reports have been filed from entities representing 38 different industry segments, as distinguished by the SIC codes of the reporting organizations. As exemplified by the projects highlighted in this report, voluntary GHG reductions since 1994 have been achieved by a wide variety of actions, including increased energy efficiency, enhanced resource recovery, waste minimization and changes in land use practices to increase terrestrial sequestration. The number of reporting entities has more than doubled since the program began, while the number of reported projects has almost tripled.

A total of 228 U.S. companies in 25 different industries or services reported to the EIA that they had undertaken 1,705 projects to reduce or sequester GHG emission reductions. The projects reported a total of 60.5 million metric tons carbon equivalent (MMTCE) or 244.5 million tons of CO_2 ($MTCO_2$) of direct reductions, 19.4 MMTCE (78 $MTCO_2$) of indirect reductions, 2.2 MMTCE (8.8 $MTCO_2$) of reductions from carbon sequestration, and 4.1 MMTCE (16.5 $MTCO_2$) of unspecified reductions.

Of the 109 organizations reporting at the entity level, 104 calculated their entity-wide GHG emissions. These entities reported direct GHG emissions of 246 MMTCE (993 $MTCO_2$), equal to about 15% of total U.S. GHG emissions. Also reported by these organizations were 40 MMTCE (162 $MTCO_2$) of indirect emissions, equal to 2% of total U.S. GHG emissions. Also, 107 entity-level reporters tallied emission reductions, including 46 MMTCE (186 $MTCO_2$) of direct emissions reductions, 7.7 (31 $MTCO_2$) of indirect emission reductions, and 1.9 MMTCE (7.7 $MTCO_2$) of emission reductions resulting from carbon sequestration projects.

In the early years of the program, reporting was dominated by electric utilities. In the first reporting year, the 95 submissions from electricity producers represented 88% of the 108 reports received. Since then, the program has seen an influx of new participants from outside the electric utility sector, representing a diverse set of other industries. Several mergers and acquisitions involving reporters to the program have accompanied the ongoing restructuring of the electric utility industry. Many of these merged entities have submitted single, consolidated reports, thus reducing the number of reports received from electricity producers. As a result, only 45% of the organizations reporting to the program for data year 2001 were from the electric utility industry.

Most projects involve actions within the U.S. Some are conducted in foreign countries, designed to test various concepts of joint implementation (JI) with other nations. Fifty-eight of the 89 foreign projects represent shares in two forestry programs in Belize and Malaysia sponsored by the electric utility industry.

The principal objective of the majority of the projects reported was to reduce CO_2 emissions. Most of these projects reduced CO_2 either by reducing fossil fuel consumption or by switching to less carbon-intensive sources of energy. Many also achieved small reductions in emissions of other gases. A total of 900 projects involved either efficiency improvements and switching to less carbon-intensive sources in the electricity industry or energy end-use measures affecting stationary or mobile combustion sources. Projects that primarily reduced CO_2 emissions also included the 87 "other" emissions reduction projects -- most of which involved either the reuse of fly ash as a cement substitute in concrete or the recycling of waste materials.

Projects that primarily affected CO_2 emissions accounted for reported direct reductions of 51 MMTCE (206 $MTCO_2$), representing 76% of the total direct reductions reported. In addition, indirect reductions totaling 8.5 MMTCE (34 $MTCO_2$) were also reported for the projects that reduced CO_2 emissions.

A variety of efforts to reduce emissions of gases with high global warming potentials (GWPs) were also reported. In this group, 293 of the reported projects (17%) reduced methane and nitrous oxide emissions from waste management systems, animal husbandry operations, oil and gas systems, or coal mines. The direct emission reductions for these projects totaled 7.9 MMTCE (32 $MTCO_2$), representing 13% of the total direct reductions reported. Indirect reductions reported for projects that reduced methane and nitrous oxide emissions totaled 11 MMTCE (44 $MTCO_2$). The 47 projects reported on the short form reduced emissions from unspecified sources by a reported 1.1 MMTCE (4.4 $MTCO_2$).

<u>Coal Mining</u>
CONSOL Coal Group reported its reductions as an entity-level reporter, without defining specific projects that were responsible for directly reducing the emissions. CONSOL was one out of the 48 companies that reported only entity-level information. 109 of the 228 companies reported entity-level information, while 61 of all the participants in the program reported both entity-level information and project-level information.

CONSOL Coal Group reported the largest individual entity-level direct emissions reduction at 5.2 MMTCE (21 $MTCO_2$), accounting for 11% of the total reported CO_2 equivalent direct reductions. These reductions are the combined effect of changes in mining operation, the initiation of coal bed methane (CBM) gas sales projects, and the internal use of CBM as a fuel.

There were 16 projects reported to specifically reduce methane emissions from coal mines, with total direct emission reductions of 538,285 metric tons (3.15 MMTCE) and indirect reductions of 96 metric tons methane (550 metric tons carbon equivalent).

Jim Walter Resources, Inc., reduced methane emissions by 242,570 metric tons (1.4 MMTCE) , mostly due to the capture and sale of gob gas to an interstate pipeline. These gob wells are drilled in advance of the longwall mining in order to assist in the removal of methane from the active mine operations. The company also practices degasification through horizontal boreholes on all their deep mines.

Two other companies contributing to the methane reductions at coal mines were U.S. Steel Mining Company, reporting direct methane reductions of 106,771 metric tons methane (0.6 MMTCE) from its two projects and El Paso Production Company, reporting direct reductions of 79,914 metric tons (0.45 MMTCE) from its project in White Oak Creek coalbed in Alabama.

None of the coal mining companies reported any sequestration projects that involved afforestation or reforestation. Mining companies are required under Subchapter B 30 CFR Surface Mining Law Regulations, to re-vegetate all post-mining areas. Under Part 715, the code requires that "a diverse, effective, and permanent vegetative cover of species native to the area of disturbed land or species that will support the planned post-mining uses of the land approved according to Sec. 715.13." If the land use category is changed, i.e., from a rangeland, cropland, hayland, or pasture to a forest land, it would have to be approved by the regulatory authority, after consultation with the landowner provided it meets the criteria outlined in Sec. 30 CFR 715.13 (d). If introduced species were to be substituted for native species, the regulatory authority would have to approve it after the appropriate field trials demonstrated the species had equal or superior utility.

While there are opportunities for mining companies to be involved with afforestation projects, regulations have not allowed companies to transform a rangeland into a forest.

Electric Utilities

Eighty-four electric power providers reported 391 projects that reduced emissions a total of 45.6 MMTCE (184 $MTCO_2$) through direct and indirect sources. Electric power projects are reported in two categories:

(1) carbon content reduction; and
(2) increased energy efficiency in generation, transmission, and distribution.

Carbon content reduction projects include availability improvements, fuel switching and increases in lower emitting capacity. Increased efficiency through generation, transmission, and distribution projects includes such activities as heat rate improvements, cogeneration and waste heat recovery, high-efficiency transformers, and reductions in line losses associated with electricity transmission and distributions. A total of 188 projects reporting 4.6 MMTCE (18.5 $MTCO_2$) were for increased energy efficiency and 225 projects representing 42 MMTCE (169 $MTCO_2$) were reported under carbon content reductions. About three-quarters of the reported electric power projects were related to nuclear power.

Of the 188 projects related to energy efficiency, 117 projects were defined as improvements in generating efficiency. Heat rate improvements at coal-fired power plants are a commonly reported means of increasing efficiency and reducing CO_2 emissions. There are numerous opportunities for improving efficiency at existing power plants. The reductions reported were 2.5 MMTCE (10.2 $MTCO_2$) – 5.56% of the total emissions reported by power companies.

FirstEnergy Corporation reported heat rate efficiency improvements on the Ohio Edison System that were accomplished through:

(1) shutdown of less efficient coal-fired boilers;
(2) installation of enhanced boiler controls; and
(3) turbine modifications.

This project reported a reduction of 8.6 trillion Btu in consumption of bituminous coal, resulting in direct reductions of 0.22 MMTCE (0.89 MT CO_2) emissions.

American Electric Power (AEP) reported 71 projects that reduced emissions. Two of these were related to emission reductions from heat rate improvement projects at their coal-fired power plants accomplished through operational changes, equipment changes, and improved load optimization. The emission reductions reported were 0.35 MMTCE (1.4 MT CO_2).

Southern Company reported one project out of 34 on heat rate improvement on coal-fired capacity. From 1990 to 1994, Southern Company improved their average net heat rate by better operation and maintenance of plant equipment. Examples include enhanced boiler heat recovery in economizer and air preheater systems, component replacement for efficiency gain (fans, heat exchangers, pumps), heat rejection upgrades, and improved turbine performance monitoring/maintenance. For 1995-2000, the average coal-fired heat rate increased, mostly due to emission control projects required by the 1990 Clean Air Act Amendments. With the number of selective catalytic reduction (SCR) systems coming on-line and installation of flue gas desulfurization (FGD) systems, further improvements in heat rates will no longer be achievable.

Tennessee Valley Authority has reported a total of 7.4 MMTCE (30 MT CO_2) direct and indirect emission reductions, with 25 projects defined.

<u>Coal Ash</u>
Thirty-seven projects were reported that reused coal ash. This accounted for indirect reductions of 1.46 MMTCE (5.9 MT CO_2) that represented over 7 million metric tons of coal ash reused.

FirstEnergy recovered 177,800 tons of fly ash to be used in the production of Portland cement, which was an indirect reduction of 0.42 MMTCE (0.14 $MTCO_2$). Fly ash substitution for Portland cement saves CO_2 emissions by displacing Portland cement that would otherwise need to be produced. CO_2 emissions saved in the Portland cement manufacturing process results from the direct combustion of fossil fuels plus from the calcination of limestone that will be avoided.

AEP sold fly ash for use in ready-mix concrete, pozzolan, and concrete block. They recycled 741,827 tons of fly ash for an indirect reduction of 0.17 MMTCE (0.58 $MTCO_2$). This was the second largest quantity of coal ash reuse. (TXU recorded the largest.)

Energy End Use

Reported reductions for the 329 energy end-use projects reported on the long form included 5.2 MMTCE (21 $MTCO_2$) from direct sources and 2.2 MMTCE (8.8 $MTCO_2$) from indirect sources. Energy end-use reductions were reported for stationary-source applications, such as building shell improvements, lighting and lighting control, appliance improvement or replacement, and heating, ventilation and air conditioning improvements. Much smaller reductions were reported for the 53 transportation projects reported on the long form, including 0.12 MMTCE (0.049 $MTCO_2$) from direct sources and 0.024 MMTCE (0.097 $MTCO_2$) from indirect sources.

Carbon Sequestration

Almost all of the 369 carbon sequestration projects reported to EIA increased the amount of carbon stored in sinks through various forestry measures, including afforestation, reforestation, urban forestry, forest preservation, and modified forest management techniques. EIA recorded that 45 of the 51 reporters involved in forestry or natural resources programs that sequestered carbon or reduced emissions in 2001 were electric utilities.

These activities accounted for 25% of the projects reported on the long form; 243 of the reported carbon sequestration projects presented 27 electric utilities' shares in nine projects conducted by the UtiliTree Carbon Company. The sequestration reported for carbon sequestration projects on the long form totaled 2.2 MMTCE (8.8 $MTCO_2$). Direct emission reductions totaling 0.0003 MMTCE (0.0012 $MTCO_2$) were also reported for a few carbon sequestration projects in which changes in forest management practices reduced fuel consumption. A further 14 carbon sequestration projects reported on the short form sequestered or avoided emissions of 0.0025 MMTCE (0.01 $MTCO_2$).

AEP accounted for the largest number of projects (14% of the 251 afforestation and reforestation projects). AEP reported 34 afforestation projects on land owned by its operating companies, which sequestered a reported 0.04 MMTCE (0.16 $MTCO_2$). Three of the projects were initiated in 2001.

AEP reported 11 projects that involved the utility's annual additions to its modified forest management efforts conducted in upland central hardwood stands. The stands are selectively harvested, removing over-mature, mature, cull, and diseased trees. Other steps are undertaken, as necessary, to improve growing space relationships and maximize the growth rates of the stands. The combined additional sequestration reported by AEP for these projects in 2001 was 0.004 MMTCE (0.017 $MTCO_2$).

FirstEnergy is involved in an urban forestry project since 1992. Under the tree source project, 17,900 trees were planted in 2001. The company provided ornamental trees, free of charge, to its Ohio customers for residential planting.

Methane Emissions

Emission reductions for the 246 methane abatement projects reported on the long form included 7.9 MMTCE (29 $MTCO_2$) from direct sources and 11 MMTCE (44 $MTCO_2$) from indirect sources. The three most frequently reported sources of methane reductions were municipal waste landfills (198 projects), natural gas systems (19 projects), and coal mines (16 projects). In addition to reducing methane emissions, projects that involved the recovery and use of methane for energy also reduced CO_2 emissions by displacing fossil fuels – such as oil and coal – that have higher carbon contents and thus produce more CO_2 when burned.

Future Commitments

Eighty-five entities reported formal commitments to reduce future emissions, to take action to reduce emissions in the future, or to provide financial support for activities related to GHG reductions. More than one-third (34%) of these entities are electricity generators participating in the Climate Challenge Program. Fifty-six other entities also reported commitments. Other voluntary programs represented among the commitments reported included Climate Wise, the Voluntary Aluminum Industrial Program, the U.S. Initiative on Joint Implementation, the Green Lights Program, the Landfill Methane Outreach Program, the Coalbed Methane Outreach Program, Motor Challenge, and the Sulfur Hexafluoride Emissions Reduction Partnership for Electric Power Systems.

There are three forms of future commitments in the Voluntary Reporting Program:

1) entity commitments;
2) financial commitments; and
3) project commitments.

Entity and project commitments parallel the entity and project aspects of emissions reporting. An entity commitment is a commitment to reduce the emissions of an entire organization. A project commitment is a commitment to take a particular action that will have the effect of reducing the reporter's emissions through a specific project. A financial commitment is a pledge to spend a particular sum of money on activities related to emission reductions, without a specific promise about the emissions consequences of the expenditure.

Twenty-five firms made 32 specific promises to reduce, avoid, or sequester future emissions at the entity level. Some of these entity-level commitments were to reduce emissions below a specific baseline, others to limit the growth of emission per unit of output, and others to limit emissions by a specific mount relative to a baseline emissions growth trend. In their reports, companies committed to reducing future entity-level emissions by a total of 25.7 MMTCE (104 $MTCO_2$) – 44% of entity-level emission reduction commitments were for the year 2000, with an additional 31% falling within the 2001 to 2005 time horizon.

Twenty-nine companies reported on commitments to undertake 182 individual emission reductions projects. Some of the commitments were linked to future results from projects already under way and forming part of the reporters' submissions. Others were for projects not yet begun. Reporters indicated that the projects were expected to reduce future emissions by 41 MMTCE (166 $MTCO_2$), most of which (24.5 MMTCE or 99 $MTCO_2$ or 60%) would be reductions of methane emissions.

Twenty-one firms made 39 separate financial commitments. The total amount of funds promised was $51 million, of which $7 million was reported to have been spent in 2001.

The Business Roundtable Climate RESOLVE Program

The Business Roundtable is an association of chief executive officers of leading corporations with a combined workforce of more than 10 million employees in the U.S. and over $3.7 trillion in revenues. In February 2003, the BRT announced the Climate RESOLVE (**R**esponsible **E**nvironmental **S**teps, **O**pportunities to **L**ead by **V**oluntary **E**fforts) program at a U.S. Department of Energy event in conjunction with the Department of Agriculture, Environmental Protection Agency and Department of Transportation. The event highlighted cooperative public and private programs to address climate change. The Climate RESOLVE program encourages BRT members to report their greenhouse gas management efforts to the Department of Energy. BRT will regularly report on progress towards the 100% participation goal.

In addition to its call for voluntary action, the Business Roundtable will give its member companies support and tools to effectively manage GHG emissions. The BRT will assist companies through workshops, one-on-one consulting support, an implementation workbook and examples of cost-effective options to reduce, avoid, offset and sequester GHG emissions.

The BRT has stated their belief that the development and deployment of breakthrough technologies will provide the most effective long-term response to concerns about global climate change. In the meantime, BRT member CEOs have pledged to apply best management practices to make American companies among the most greenhouse-gas efficient in the world.

2.3 Improvements in Reporting Protocols

2.3.1 Corporate GHG Accounting and Reporting

Global climate change is viewed as one of the important issues of the 21st century. The momentum for responding is increasing as governments are adopting aggressive actions, including potential ratification of the Kyoto Protocol in 2003, and establishing national, statewide, and regional emissions reporting initiatives or trading schemes. There also is increasing pressure on businesses in the developed world to demonstrate that they are taking responsibility to quantify and manage their GHG emissions, particularly for carbon intensive industries.

Proactive companies are taking steps to identify not only the risks and challenges associated with the evolving climate change arena, but also the business opportunities that could be developed. To do this, however, companies must first have an understanding of the extent and nature of their GHG emissions.

2.3.2 Hierarchy of Existing GHG Accounting and Reporting Initiatives

A range of programs currently exist for reporting, registering, and trading GHG emissions and emissions reductions. While these programs differ from each other, one thing they have in common is the need for guidance on how GHG emissions are accounted for and reported. The approaches taken by these programs often differ widely, however, even among programs with similar purposes.

The programs referenced within this chapter can be grouped into four categories:

1. U.S. Government-Sponsored Programs at the Federal and State Level
    a. DOE's Voluntary Reporting of Greenhouse Gases Program - 1605(b) Program
    b. EPA's Climate Leaders Program
    c. The California Climate Action Registry
    d. The New Hampshire Voluntary GHG Reductions Registry
    e. The New Jersey Open Market Emissions Trading Program
    f. The Wisconsin Voluntary Emission Reduction Registry

2. Programs Offered by Non-Governmental Organizations
    a. The Climate Neutral Network
    b. The Climate Trust
    c. Environmental Defense Fund's Partnership for Climate Action
    d. Environmental Resources Trust's GHG Registry
    e. World Wildlife Fund's Climate Savers Program

3. International Initiatives
    a. The UNFCCC (e.g., National Registries & Flexible Mechanisms)
    b. The World Bank's Prototype Carbon Fund
    c. The World Resources Institute (WRI)/World Business Council for Sustainable Development (WBCSD) Greenhouse Gas Protocol Initiative
    d. The American Petroleum Institute's (API) Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry
    e. The Chicago Climate Exchange

4. Existing Programs in Specific Foreign Countries or Regions
    a. The Australian Greenhouse Challenge
    b. Denmark's National GHG Trading Scheme
    c. EurElectric Group's GHG Emissions Trading Simulations
    d. The European Union's Emissions Trading Directive
    e. The Netherlands' ERUPT (JI) and CERUPT (CDM) Tenders
    f. The United Kingdom's National Emissions Trading Scheme

Within these categories, the programs have a range of purposes. Typically they exist to promote public recognition of efforts to reduce emissions, to provide protection for emissions baselines (e.g., ensure that voluntary actions are taken into account if and when a mandatory regime is adopted), or to promote emissions trading. In some cases, the programs serve more than one purpose.

2.3.3 Initiatives With Heavy Industry Participation

While there is no universally accepted international business standard for estimating GHG emissions, three efforts have enjoyed heavy participation from the private sector:

1. DOE's Voluntary Reporting of Greenhouse Gases Program – 1605(b)

2. API Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry, (API, 2001)

3. WRI/WBCSD *The Greenhouse Gas Protocol* and associated Stationary Combustion Tool (WRI/WBCSD, 2001)

The DOE Program

The DOE's Voluntary Reporting of Greenhouse Gases Program, created under Section 1605(b) of the Energy Policy Act of 1992, allows any company, organization or individual to establish a public record of emissions, reductions, or sequestration achievements in a national database. Reporters can gain recognition for environmental stewardship, demonstrate support for voluntary approaches to achieving environmental policy goals, support information exchange, and inform the public debate over GHG emissions.

During 2002, the President directed the Secretary of Energy, working with the Secretaries of Commerce and Agriculture and the Administrator of the EPA, to propose improvements to the current 1605(b) program to "enhance measurement accuracy, reliability and verifiability, working with and taking into account emerging domestic and international approaches." The President also requested recommendations "to ensure that businesses and individuals that register reductions are not penalized under a future climate policy, and to give transferable credits to companies that can show real emissions reductions."

The API Compendium

The API Compendium project reviewed numerous GHG protocols and methodology documents in an effort to compare and contrast different greenhouse emission estimation techniques and develop a document of internationally recognized best practices. Protocols from participating petroleum companies and publicly available guidance documents and inventory protocols were included in this detailed review. Internationally recognized sources reviewed under the API project include:

- EPA's AP-42 (EPA, 1995 including supplements A through F);
- Intergovernmental Panel on Climate Change (IPCC, 1996);
- Emission Inventory Improvement Program (EIIP, 1999);
- Energy Information Administration (EIA, 1996; EIA, 2001); and
- WRI/WBCSD (WRI/WBCSD, 2001)

API is currently reaching out to other protocol development organizations (governmental and non-governmental) to gain broad peer-review of its efforts, with the ultimate goal of achieving harmonization of estimation methods and improved global comparability of emission estimates. Although the focus of the Compendium is on oil and gas industry operations, methodologies presented for combustion sources and energy generation are directly applicable to electric utility operations.

The GHG Protocol Initiative

The WRI/WBCSD GHG Protocol Initiative is an international undertaking to promote the use of standardized methods for estimating and reporting GHG emissions. Proposed principles and standards are provided for developing a corporate GHG inventory and for performance reporting. A separate spreadsheet tool is available for estimating emissions from stationary combustion sources and energy generation. The WRI/WBCSD GHG Protocol is widely cited and recognized as the accepted approach for developing GHG inventories.

Module I of the WRI/WBCSD GHG Protocol addressing entity-wide reporting has been completed. Module II on project-based reporting was launched in 2002 and is not expected to be completed until the end of 2003. WRI is seeking feedback on reporting efforts using Module I guidelines.

The EPA Climate Leaders program is using a reporting protocol based on a modified version of the WRI/WBCSD GHG Protocol. It held a workshop October 2002 to discuss feedback on the reporting protocol and GHG reduction-setting methodology. Climate Leaders has also "released for comment"[1] its first draft GHG Protocol document, the Stationary Combustion Module. During 2003, EPA will seek comments on the draft Climate Leaders GHG Inventory Protocol documents. The protocol will be released in stages as individual modules are completed. After gathering feedback on all of the inventory protocol modules, EPA will integrate comments, finalize the modules, and publish the protocol, updating it as needed.

2.3.4 Accounting and Reporting Recommendations

Consistency in Accounting and Reporting Metrics

The U.S. government, through the DOE, should make every effort to ensure that:

- Changes to the 1605(b) program are consistent with the accounting and reporting principles supported by U.S. industry (e.g., API and GHG Protocol Initiative); and
- Wherever possible, be consistent with international accounting and reporting best practices in an effort to reduce the accounting and reporting burden of U.S. multi-national corporations.

Nature of Reporting

Reporting should:

- Stay flexible, including retention of the flexibility to report either entity-wide emissions or project-specific reductions only;
- Accommodate multiple purposes for reporting, including (but not limited to) recording emissions and achievements, informing public debate, participating in educational exchange, as well as providing transferable credits, baseline protection and credit for past actions; and
- Allow the reporter to specify those projects and reductions for which transferable credits, baseline protection, and/or credit for past action is being sought versus those reported activities for which it is not being sought.

[1] This is not public comment via the Federal Register.

Reference Cases

1. Multiple options should be available for setting reference cases.[2]
2. Modified reference cases[3] should remain an option (including those developed from emission rates).

Project-Based "Reductions"

1. Accounting and reporting guidelines should:
   - Continue to allow project "reductions" to be reported separately from the reporting of entity-wide emissions. If entity-wide emissions are reported, the ability to report project-level reductions should not depend on the entity-wide emissions showing a reduction.
   - Continue to allow reporting of off-site sequestration projects, including abandoned mine land reclamation programs.
   - Include projects that avoid emissions and provide an indirect emissions benefit by reducing energy consumption (including energy efficiency and DSM).
   - Continue to allow reductions from international projects, including those approved by governments under activities implemented jointly (under the UNFCCC) and CDM and JI flexible mechanisms (under the Kyoto Protocol).
2. Reporters should distinguish between projects where they have direct control (*e.g.*., electricity generators' heat rate improvement programs, enhanced CBM recovery, etc.) versus those activities where others may affect the level of direct reductions (*e.g*., electric utilities' DSM programs).

Entity-Wide Reporting

1. Entities should continue to have the flexibility to choose their reporting boundaries and otherwise define the scope of their reports in a way that is consistent with a specific industry's best practices.
2. Indirect emissions should continue to be a separate, optional category for reporting.
3. If an entity *opts* to assign a portion of its direct emissions from their operations to purchasers of their products, they should also report that portion assigned to their customers as an indirect emissions reduction (e.g., credit) against their direct emissions, in order to accurately account for all of their emissions. Any reporting in this manner should be in addition to the reporting of all direct emissions of GHGs from their operations.

[2] "Reference case" is the term used in the 1605(b) guidelines for a project baseline, or what the emissions would have been in the absence of the project.

[3] "Modified reference cases" are references cases that recognize that, even in the absence of the project, future emission levels would differ from historic levels.

4. Reporting entities should be urged (but not required) to report other categories of direct emissions if they believe that the emissions from any of the other categories (*e.g.*, fleet vehicles, methane, N_2O) are greater than a *de minimis* amount established for that industry.

5. Quantification of reductions based on *entity-wide* emissions should meet the same standards for "leakage" (and other relevant criteria) that are applied for quantification of reductions from *projects*.

Verification

1. Third-party verification should be optional (e.g., it may be desirable for some projects in order to create fungible/tradable emission reduction credits).

2. In those cases where reporters have elected to have third-party verification of projects, it would be helpful to have some uniform standards for such verification.

Confidentiality

1. Trade secret and commercial or financial information that is privileged or confidential should continue to be protected under the Freedom of Information Act, Section 1605(b)(3) or other applicable law. Any other approach would discourage participation in a voluntary program.

SECTION 3: EVALUATION OF RESEARCH AND DEVELOPMENT NEEDS FOR GREENHOUSE GAS MANAGEMENT

Introduction

Approximately one-third of all CO_2 emissions due to human activity arise from the combustion of fossil fuels used to generate electricity, with each power plant capable of emitting several million tons of CO_2 each year. This contributes to the build-up of GHGs in the atmosphere. Policy proposals to limit emissions of CO_2 and other GHGs are being considered at the international, national, regional, and local levels.

International efforts to limit GHG emissions are based primarily on the United Nations Framework Convention on Climate Change (UNFCCC), which seeks "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." Although a target concentration has not been specified, actions to reduce emissions of CO_2 and five other major GHGs are proceeding through policy instruments, such as the emission reduction targets set for developed countries under the 1997 Kyoto Protocol.

The U.S. has not agreed to the GHG reduction targets set forth under the Kyoto Protocol, but the Bush Administration has proposed a Global Climate Change Initiative (GCCI) to voluntarily reduce the carbon intensity of the U.S., as measured by CO_2 emitted per unit of GDP, over the next 10 years. The GCCI has set forth the goal of significantly reducing the GHG intensity of the U.S. economy over the next 10 years, while maintaining the economic growth needed to finance investment in new, clean energy technologies. This will require increased R&D investments with a heightened emphasis on carbon sequestration and reductions in non-CO_2 GHG emissions, such as methane and N_2O.

Because more than 85% of the CO_2 emitted by the power sector originates from coal, achieving the GCCI-targeted 18% reduction in GHG intensity over the next decade within the power sector will be a challenge. By focusing on GHG intensity as the metric of choice, the government must promote vital R&D while minimizing the economic impact of GHG emission reduction on the U.S. This goal could be accomplished through a synergistic, three-pronged approach, consisting of:

- Increasing the efficiency of the energy system;
- Increasing the use of low-carbon fuels; and
- Developing technologies to capture and store CO_2 from fossil fuels used for energy.

A portfolio of new advanced technologies that would increase energy system efficiency holds great potential to reduce GHG emissions. In addition, the development of carbon capture and sequestration technologies will play a critical role if the U.S. is to successfully manage its GHG emissions.

Plotting and Following the Technology Roadmap

If GHG management on the scale envisioned in various futurist scenarios is required, it will be a massive technical and economic undertaking. On the other hand, if the international community's will to utilize its abundant fossil fuel resources is not to be denied, the undertaking will require the development and deployment of new technology at an unprecedented pace and scale. To achieve this, particularly in an international context, will take a clear vision of what is needed and what must be done to accomplish it. Therefore, it is imperative that there be broad consensus embodied in national energy policy that outlines the overall goals, time frame and costs for achieving them in a comprehensive technology roadmap. The roadmap must include both a range of options for achieving the goals and a framework for allocating resources to meet the goals with the greatest economic and temporal efficiency.

Recently, there has been a substantial effort in the technical community to achieve agreement on a common road map for coal utilization technology directed at the production of electricity and fuels. This road map has been drawn from individual roadmaps of the DOE, the Coal Utilization Research Council, and EPRI, and includes greenhouse gas management as a specific objective. It is important that the roadmapping effort continue to assist DOE, private industry and the public to update and focus performance objectives, technology options and economic resources.

3.1 Energy Efficiency Improvements

3.1.1 Summary

Enhancing generation efficiency can be the most cost-effective approach for reducing CO_2 emissions and simultaneously improving the utilization of coal, a critical domestic energy resource. With higher efficiency, less coal is used to produce the same power output, resulting in reduced emissions of pollutants and GHGs. The application of highly efficient, clean power generating systems is essential for coal to maintain its position as the most important energy source for power generation.

As a result of the DOE-industry sponsored CCT Program, a number of coal-based power generating systems of increased efficiency are now commercially available. Others will be available for demonstration and deployment after 2010. Four specific technologies are discussed in this section, because of their readiness for application or significant promise of performance in the near future, with further development:

- Pulverized coal (PC) combustion with supercritical (SC) and ultra-supercritical (USC) steam;
- Pressurized fluidized bed (PFBC) combined cycle with topping combustor (PFBCwTC);
- Integrated gasification combined cycle (IGCC); and
- Hybrid gasification/fuel cell/GT/steam (DOE's Vision 21Cycle).

These technologies offer 45% cycle efficiency (LHV), with a potential 25% CO_2 emissions reduction compared to currently installed capacity. U.S. and international R&D efforts are in progress to develop further materials for USC plants with prospects of efficiency increases up to 50% (LHV). Such plants are expected to be available by 2010.

Capital costs, operating costs, and the cost of electricity are lower for PC-SC steam than for the combined cycles. However, PFBCwTC and, especially, IGCC could become more competitive when it becomes commercially viable to add CO_2 capture equipment.

Vision 21 Cycle aims at "zero emissions" and >60% cycle efficiency**.** Development of this advanced power generation system is worthy of governmental and industrial support. It is the best prospect for extending coal use while meeting more stringent environmental limitations.

3.1.2 Coal-Based Generation Technologies for New Plants

The efficiency of the existing coal-based power plant fleet in the U.S. is about 35% (LHV). Advanced coal-based power generation technologies are able to generate electricity at significantly increased efficiency (>45%, LHV). Several of these technologies have been developed over the last 15 years through successful government-industry cooperation under DOE's CCT Program, and are now commercially available.

Higher efficiency is the key to the reduction of all emissions, since higher efficiency means less fuel is burned and fewer pollutants are emitted. This includes GHGs such as CO_2. Until CO_2 capture and removal from flue gas becomes a commercially available technology, efficiency increases will remain the most practical and cost-effective method for mitigating CO_2 emissions.

<u>SC and USC Technology</u>
PC-SC boilers have been in use since the 1930s. With improvements in materials and efficiency, this system has become the choice of new PC plants worldwide. Efficiency improvements have been achieved by using higher temperatures. In subcritical steam cycles, the maximum practical efficiency is just under 40% (LHV). The efficiency of a PC steam plant can be increased in small steps to beyond 45% (LHV) using SC steam parameters as shown in Figure 1 (Schilling [1]). The diagram illustrates reduction in waste heat loss, improved combustion to reduce excess air, and reduction in stack temperature.

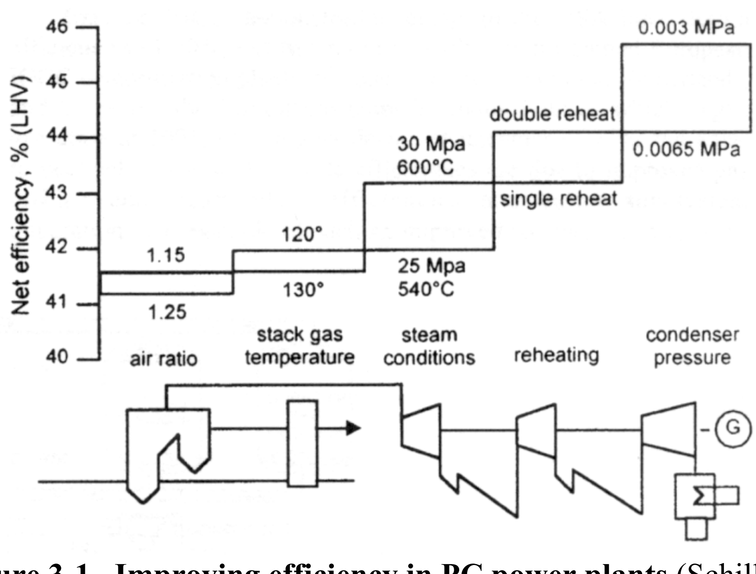


Figure 3-1. Improving efficiency in PC power plants (Schilling [1])

SC steam parameters of 3750 psi/1000 °F single or double reheat with efficiencies that can reach 42% (LHV) represent a mature, commercially available technology for U.S. power plants.

In several papers [2-8], the EPRI reviewed the history and performance of SC units in the U.S. and in the former Soviet Union, where most of the SC plants have been operated since the 1930s. SC plants also have a long history in the U.S. The original Eddystone Unit 1 with the most advanced steam parameters of 4800 psi/1150 °F was constructed in1960 and is still in operation. There are 157 PC-SC power plants in the U.S. These plants show significant efficiency advantages of up to three percentage points, without increased outages, over subcritical units.

Further improvement in efficiency achieved by USC parameters is dependent on the availability of new, high-temperature alloys for superheaters, reheaters, and steam turbines. The state of development and new USC plant commissioning internationally are shown in Table 3-1. USC steam plants in service or under construction in Europe and in Japan during the last five years are listed in Table 3-2. Today, steam parameters of 4500 psi and 1110°F can be realized, resulting in efficiencies >45% (LHV) for bituminous PC power plants. There are over five years of experience with these plants in service, with excellent availability.[2] This improved efficiency represents a significant 25% reduction in CO_2 emissions, compared to the emissions from existing coal-fired capacity.

EPRI is the technical lead organization in a program of materials development [2] aimed at steam temperatures in excess of 1300°F and enabling further efficiency gains up to 50% (LHV). The program is undertaken by DOE at its National Energy Technology Laboratory (NETL) and the Ohio Coal Development Office, with U.S. boiler manufacturers as participants and major contractors. Specific technical issues being addressed include maintaining efficiency at partial load, and the effect of load changes on the lifetime of boiler and turbine components.

International efforts, such as the USC Materials Consortium in the U.S., and AD700 in the European Union aim for further improvement of USC power generation with steam parameters of 5440 psi and 1292/1328 °F and efficiencies of 50% (LHV). Such plants are expected to be available within a decade. Application of SC steam cycle parameters is also planned for FBC systems in order to improve efficiency.

Table 3-1. International materials development. (Blum and Hald) [2]

Japan	USA	Europe
Development and Plant Operation: EPDC	Development: EPRI	Development: Cost
1981-2000	EPRI Projects: 1978-2003	Cost 501/522: 1983-2003
Turbine and boiler -Materials development -Component manufacture -Pilot plant operation (50 MW) -Target: 300 bar, 630 °C/ 630 °C	-Basic studies, turbine and boiler -Thick-walled pipe steels (USA, J, EU -Standardization achieved -Trial components in service	Turbine and boiler -Interaction with VGB, Brite-Euram, Marcko, ECCC, etc. -All major power plant components -Target: 300 bar, 620 °C/ 650 °C
Power Plant Orders		Power Plant Orders
-1000 MW, 241 bar, 593°C, 593°C, comm 97 -1050 MW, 250 bar, 600°C, 610°C, comm 01 - 600 MW, 250 bar, 600°C, 610°C, comm 02		-400 MW, 285 bar, 580°C, 580°C, comm 97 -530 MW, 300 bar, 580°C, 600°C, comm 01 -975 MW, 260 bar, 565°C, 600°C, comm 02
NIMS Materials Development	DOE Vision 21	Thermie AD700
1997-2007	2002-2007	1998-2013
-Ferritic Steel for 650°C	Materials development and qualification Target: 350 bar, 760°C (870°C)	-Materials development and qualification -Component design and demonstration plant demo Target: 400-1000 MW, 350 bar, 700°C, 720°C

Table 3-2. USC plants in service or under construction in Europe and Japan.
(Blum and Hald 2002) [2]

Power Station	Cap. MW	Steam Parameters	Fuel	Year of Com.	Eff. %	Boiler/Steam Line Materials	Turbine Materials
Matsuura 2	1000	255 bar/598°C/596°C	PC	1997		Super304H/P91	TMK1
Skaerbaek 3	400	290 bar/580°C/580°C/580°C	NG	1997	49	TP347FG/P91	COST 501 F
Haramachi 2	1000	259 bar/604°C/602°C	PC	1998		Super304H/P91	HR1100
Nordjylland 3	400	290 bar/580°C/580°C/580°C	PC	1998	47	TP347FG/P91	COST 501 F
Nanaoota 2	700	255 bar/597°C/595°C	PC	1998		TP347FG/P91	Toshiba 12Cr
Misumi 1	1000	259 bar/604°C/602°C	PC	1998		Super304H/HR3C/P91	TMK2/TMK1
Lippendorf	934	267 bar/554°C/583°C	Lignite	1999	42.3	1.4910/P91	COST 501 E
Boxberg	915	267 bar/555°C/578°C	Lignite	2000	41.7	1.4910/P91	COST 501 E
Tsuruga 2	700	255 bar/597°C/595°C	PC	2000		Super304H/HR3C/P122	Toshiba 12 Cr
Tachibanawan 2	1050	264 bar/605°C/613°C	PC	2001		Super304H/P122/P92	TMK2/TMK1
Avedore 2	400	300 bar/580°C/600°C	NG	2001	49.7	TP347FG/P92	COST 501E
Niederaussen	975	265 bar/565°C/600°C	Lignite	2002	>43	TP347FG/E911	COST 501E
Isogo 1	600	280 bar/605°C/613°C	PC	2002		Super304H/P122	COST 501E

Materials Guide
Superheater:
TP347FG:Fine Grain 18 Cr10NiMoNb   Super304H: 18Cr9Ni3Cu   HR3C:25Cr20Ni   1.4910: 18Cr12Ni2 1/2Mo

Steam Lines and Headers:
P91: 9CrMoVNb   P92: 9Cr1/2Mo2WVNb   E911: 9CrMoWVNb   P122: 11Cr1/2Mo2WCuVNb

Turbine Rotors
COST 501 F: 12CrMoVNbN101   COST 501 E: 12CrMoWVNbN1011   HR1100: 111Cr1.2Mo0.4WVNbN
TMK1: 10Cr1.5Mo0.2VNbN   TMK2: 10Cr0.3Mo2W0.2VNbN   Toshiba: 11Cr1Mo1WVNbN

PFBC

PFBC has all the advantages of atmospheric fluidized bed combustion (AFBC), including sulfur capture in the bed, low-NOx emissions, and the capability to use low-quality fuels, plus the enhanced efficiency of combined-cycle operation. While the low temperature of the fluidized bed is advantageous for avoiding “thermal NO” formation, it has the disadvantage of nitrous oxide (N_2O) emission and an inability to take advantage of the higher inlet temperature range of modern gas turbines.

PFBCwTC responds to the need for a higher gas turbine inlet temperature. In this cycle (Figure 3-2), a coal-water slurry is injected into a pressurized carbonizer where it undergoes mild gasification to produce a low heating value syngas and char. The char is burned in a PFBC boiler with high excess air, and the 1600 °F combustion products are cleaned of particulate and alkalis, and then enter the gas turbine. Sulfur is captured in the PFBC boiler and in the fluidized bed carbonizer by adding dolomite. The syngas is injected into the topping combustor, where it is burned to raise the temperature of the PFBC exhaust gas at the inlet to the gas turbine to 2280 °F. This temperature rise increases the cycle efficiency to about 47% (LHV). N_2O emissions are eliminated because the N_2O decomposes at the elevated temperature in the topping combustor.[10]

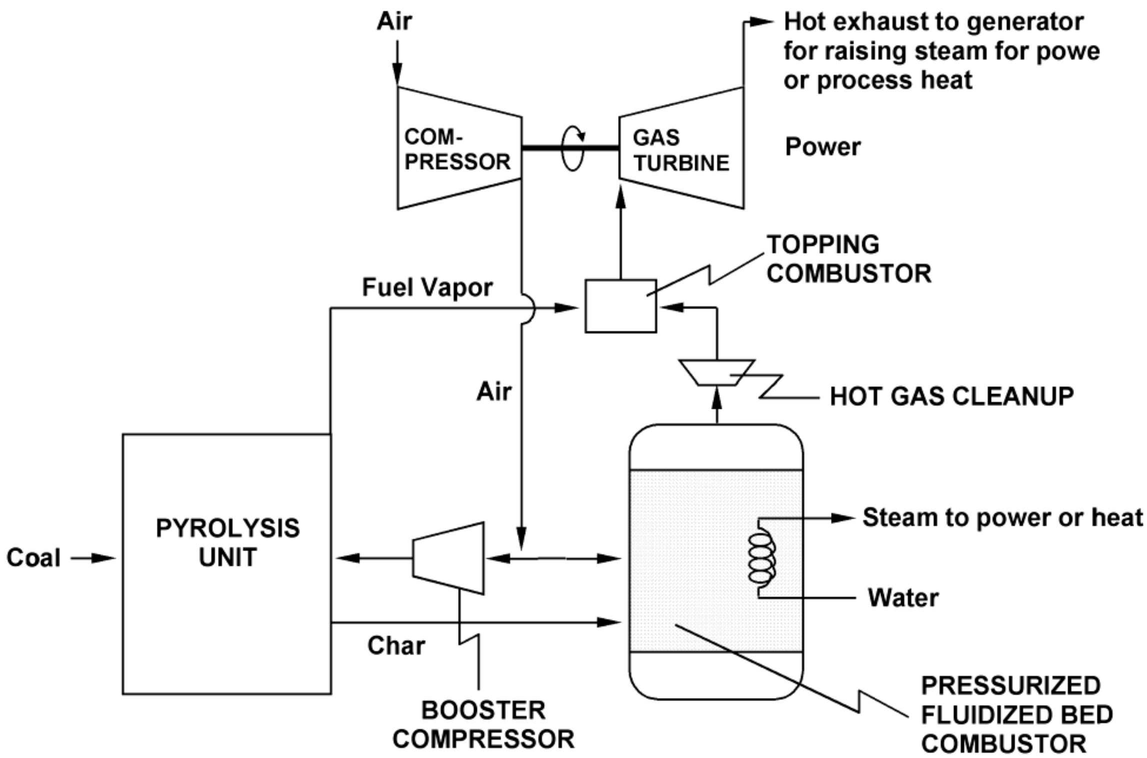


Figure 3-2. Pressurized Fluidized Bed with Topping Combustor.

Further improvements in efficiency can be obtained by the application of advanced gas turbine technology and, on the steam side, by SC steam parameters with high-temperature double reheat. Commercial realization has been hampered by slow progress on hot gas filter development, expense of turbines for this application, and complex plant integration. The future of PFBC is uncertain.

IGCC

IGCC involves the total gasification of coal with oxygen and steam to produce a high heating value syngas. The syngas is cleaned of particulate, alkalis, ammonia, and sulfur compounds and the syngas is burned in a gas turbine with low-NOx combustors. IGCC also produces steam for a steam power cycle. Main features of IGCC are shown in Figure 3-3.

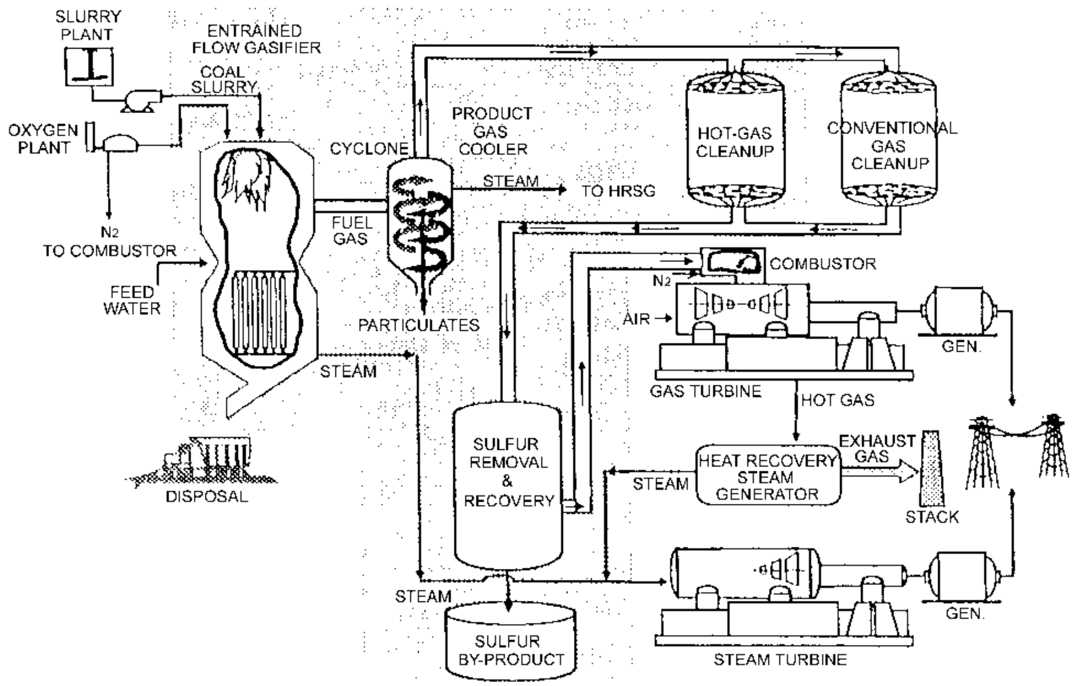


Figure 3-3. Integrated Gasification Combined Cycle (IGCC).

IGCC is the cleanest advanced coal technology, and has been successfully demonstrated at full commercial scale over the past 7-8 years, although long-term reliability and availability concerns remain. The future of IGCC depends on further reductions in capital and operating costs and increases in overall efficiency. The capital cost is presently high, mainly for the oxygen-blown gasifier, which requires an air separation plant for producing oxygen. There is a need for more complete integration of the various subsystems, such as the gasifier air separation plant, syngas coolers and cleanup, gas turbine, and steam plant.

Existing IGCC demonstration plants in the U.S. have efficiencies just below 40% (LHV). Two European IGCC demonstration plants (Buggenum in the Netherlands and the Puertollano plant in Spain, both of which began operation in 1993) have higher design efficiencies of 43% and 45% (LHV), respectively. The higher cycle efficiencies are mainly due to improved gas turbine and steam plant efficiencies and better sub-system integration. Current work being done by the gas turbine manufacturers on IGCC is aimed at utilizing ultra-high efficiency H-Class gas turbines designed and developed in a DOE-funded program. The goal is to achieve an efficiency greater than 45% (LHV) and to reduce the cost. A recent estimate indicates that a 500 MW IGCC plant would cost approximately $1,300/kW in 2002 dollars. [12] At that price, IGCC plants are not economically competitive with other advanced coal-based systems. Further considerations may, in the future, tilt the balance in favor of IGCC applications, including the facts that:

- IGCC lends itself to the efficient capture and removal of CO_2 from the high pressure syngas; and
- Mercury emissions can be controlled at relatively low cost.

DOE's Vision 21 Cycle

One of the most promising advanced coal-based cycles with "zero emissions" is DOE's Vision 21 Cycle[13] (one example is presented in Figure 3-4). In this cycle, syngas produced in an oxygen-blown gasifier is cleaned to remove contaminants harmful to the gas turbine. CO_2 is also captured. The clean syngas is composed mainly of H_2 and CO. The H_2, along with compressed air, is used to generate electricity in a solid oxide fuel cell, and the CO is burned in a combustion turbine that drives the air compressor. The efficiency could reach 60% (LHV) in this "zero emission" scheme. Several advanced concepts, including Integrated Gasification Fuel Cell, might meet these ambitious goals. In this concept, high-pressure compressor exhaust is introduced into the fuel cell. The fuel cell exhaust is used in a gas turbine to produce additional power without the addition of fuel in the gas turbine. The gas turbine exhaust can then be used in the steam turbine to produce additional power. DOE estimates that 63% efficiency (LHV) is achievable by 2010[13], when it should be ready for demonstration. The combination of high efficiency and CO_2 capture will result in significant reductions in CO_2 compared to existing coal-fired technologies.

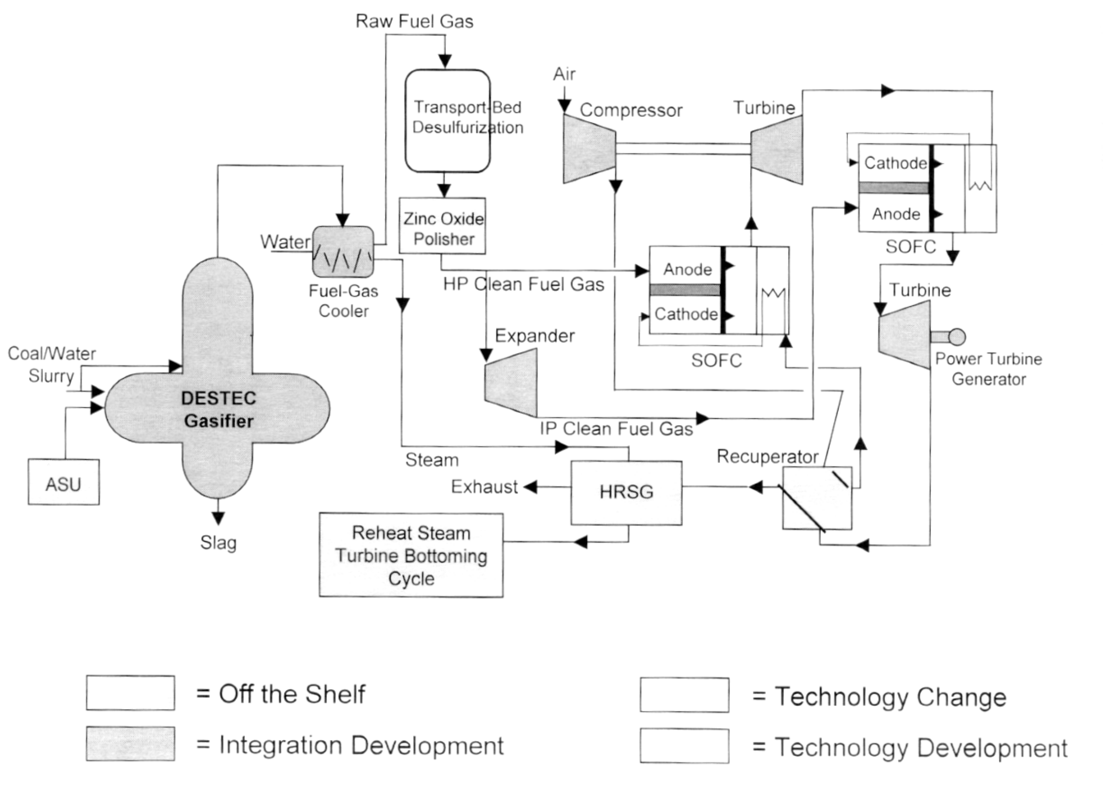


Figure 3-4. Gasification/Fuel Cell/Gas Turbine/Steam Turbine Cycle (DOE Vision 21). [11]

Comparison of CCTs

Advanced power generation schemes vary in efficiency, capability for CO_2 capture, commercial availability, and cost. Potential efficiencies of PC, PFBC, and IGCC as a function of gas turbine inlet temperature are illustrated in Figure 3-5. [14][15]). As the gas turbine inlet temperature rises, so does the combined cycle efficiency.

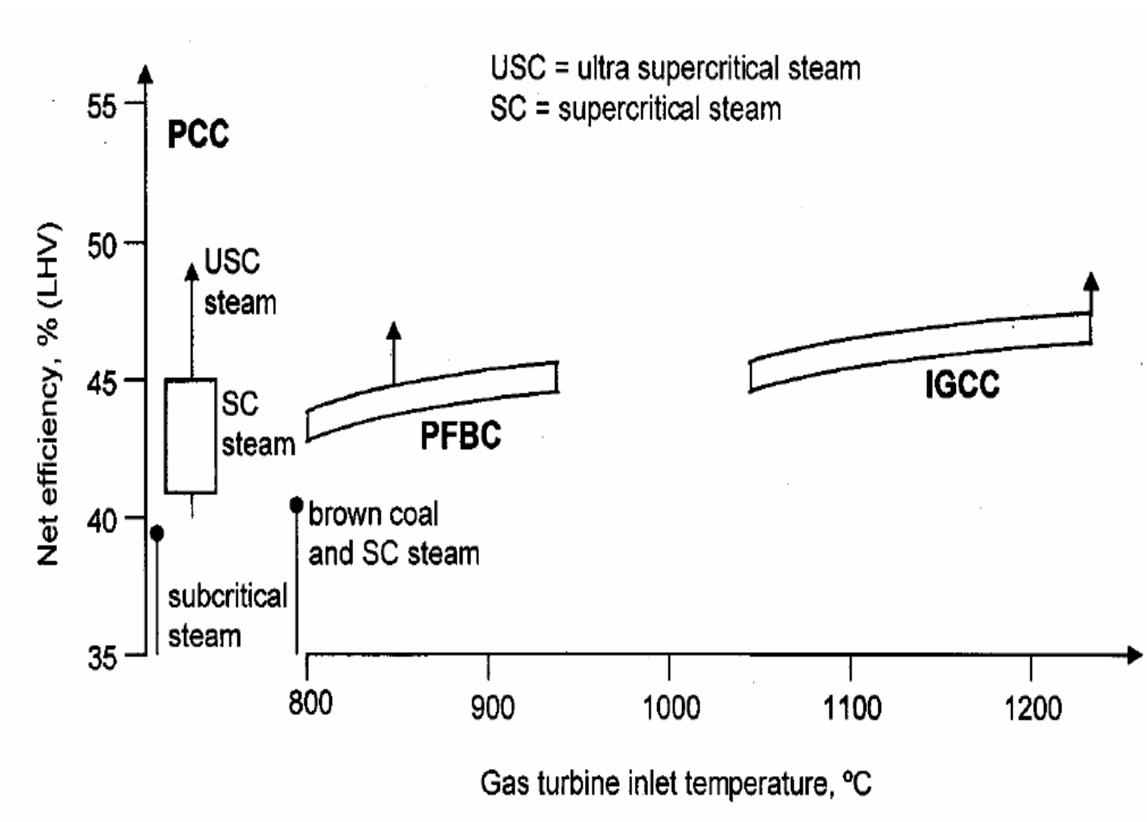


Figure 3-5. Effect of gas turbine inlet temperature on combined cycle efficiency.

Options for coal-based generation, efficiency, and CO_2 emissions are presented in Figure 3-6. The diagram shows the significant effect of the cycle efficiency upon CO_2 emissions. SOx, NOx, and PM are also proportionately reduced with increasing efficiency as illustrated by a comparison of emissions and by-products of different 600 MW plants in Figure 3-7.[16] The excellent environmental performance of IGCC is also illustrated.

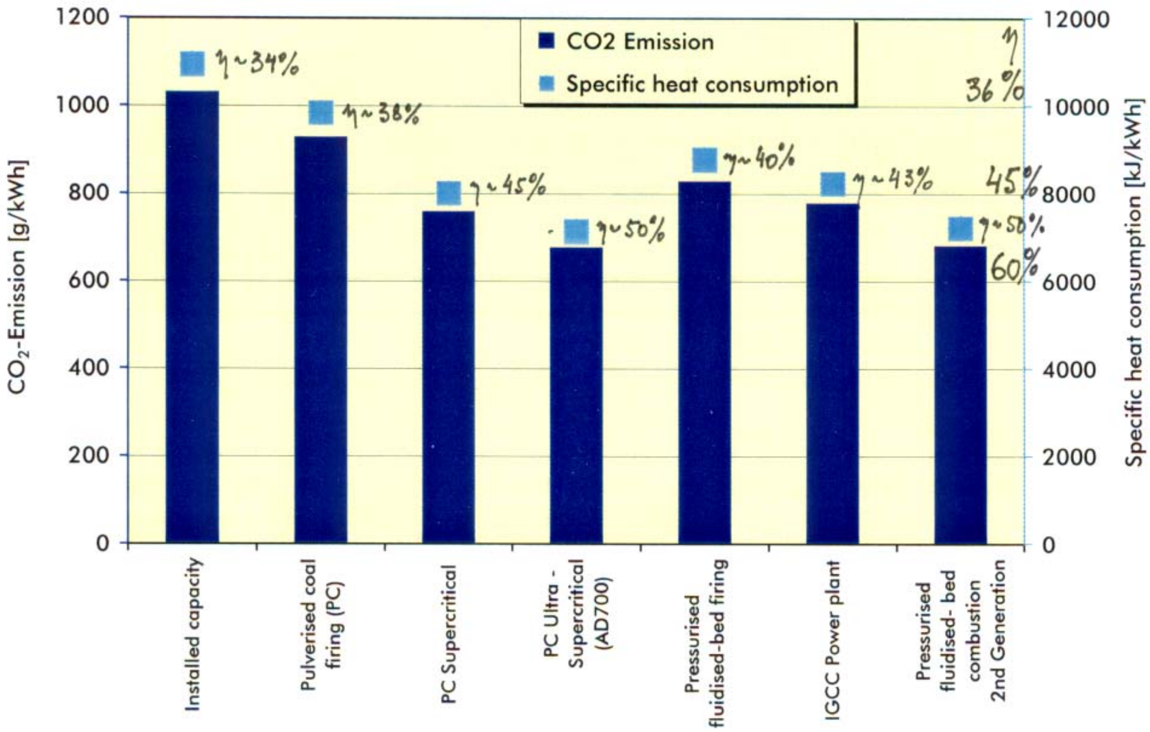


Figure 3-6. Efficiency of and CO$_2$ Emissions from Advanced Power Plants. (Stamatelopoulos et al. 2002) [16]
(1000g/kWh=2.205 lb/kWh and 8000 kJ/kWh=7584 Btu/kWh)

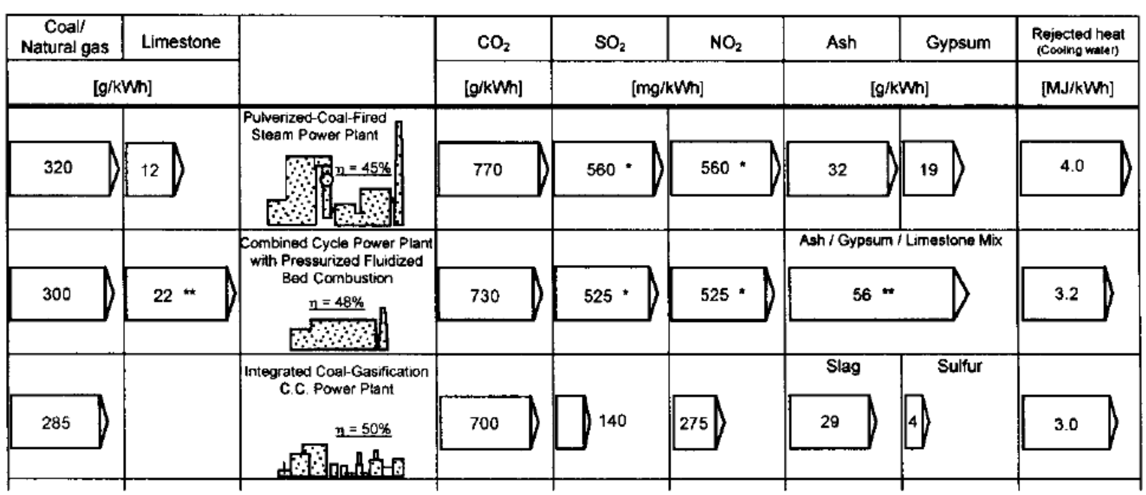


Figure 3-7. Comparison of emissions and byproducts for different 600 MW power plants. (after Haupt et al. 1998) [17]

The costs of the PFBCwTC and of IGCC relative to that of PC-SC units have been assessed by a team at Electricité de France)[18]. Table 3-3 shows that, at the time of their calculations, the cost of electricity (COE) produced by an IGCC plant or a PFBCwTC plant was estimated to be 16% and 7% higher, respectively, than that produced by PC-SC. The higher cost of IGCC, however, might be weighed against its superior environmental performance and its potential for CO_2 capture. In the meantime, PC-SC remains the cost-effective advanced coal-based power technology option.

Table 3-3. Advanced Power Generating Plant Costs as % of PC-SC costs. (after Delot et al. EDF 1996) [18]

Technology	PC/SC	PFBCwTC	IGCC
Space requirement (acres)	2.2	1-1.7	7
Net Efficiency (% LHV)	45	47	44.5
Capital cost (%)	100	106	118
O&M costs (%)	100	145	155
Relative COE (%)	100	107	116

Two recent EPRI Reports [19, 20] provide further support for IGCC with CO_2 removal. It is estimated [19] that, given a coal price of $1.24/MBtu, the breakeven point with natural gas combined cycle (NGCC) for the lowest COE occurs at a natural gas price of $4.00/MBtu. Above that gas price, IGCC with CO_2 removal will have lower COE than NGCC with CO_2 removal, and will produce electricity for 20% lower cost than PC-SC plants with CO_2 removal.

3.1.3 Technologies for Existing Plants

Increasing the Efficiency of Existing Power Generation Equipment

In order for coal to continue its role in supplying more than one-half of all electricity generated in the U.S., it will be necessary to develop advanced coal-based technologies which will be able to generate electricity at significantly higher efficiency than existing plants. A wide range of technologies, including boiler and steam turbine enhancements, are available for retrofitting existing units.

Technologies for retrofit include:

- Improved materials for steam-generation and superheater tubing;
- Steam turbine modernization improvements and upgrades;
- Control system improvements, i.e. neural networks;
- General plant efficiency improvements; and
- Consolidation of multiple, smaller inefficient units to larger, more efficient units.

Recent examples of the success of such retrofits include turbine upgrades (more aerodynamic steam paths) that were made on two 400-MW rated units to obtain an additional 25 MW per unit (a 6% increase in efficiency). No additional steam was required from the boiler. Another utility plans to replace existing turbine blades with a new, more durable blading configuration to increase the efficiency of two turbines by 4.5% each. Neural networks, which interface with existing control systems and provide real-time combustion optimization, have been shown to increase efficiency by up to 0.5%, still a notable increase. Overall, 5% efficiency increases could be readily accomplished across the fleet of existing units, at low cost.

Repowering With More Efficient Technologies
DOE's CCT Technology Program has demonstrated advanced coal-based technologies which can be used to repower existing units to become significantly more efficient. A prime example of this is repowering with IGCC. Repowering an existing coal-fired plant with IGCC will typically provide considerable opportunities for reducing costs by optimizing the reuse of existing steam cycle equipment, cooling tower and other infrastructure (i.e., buildings, coal handling systems, plant water systems, existing substation and transmission system components). Repowering (or brownfield application) with IGCC results in a significant increase in efficiency. Since less fuel is used for the same amount of generation, emissions per MWh are reduced proportionally. This includes SO_2, NOx, and CO_2.

Two of the IGCC projects constructed as part of the CCT Technology Program have efficiencies of approximately 38% (HHV). With lessons learned from these facilities, as well as continued enhancements to the gasification and combined cycle portions of this technology, present IGCC technology can provide an efficiency of approximately 41% (HHV) when retrofitted to existing plants. For existing units, an improvement of 6 percentage points, from 35% to 41%, is actually a 17% increase, with emissions of CO_2 being reduced proportionally. One very good example of the size of potential CO_2 emission reductions is Global Energy's Wabash River Plant in Indiana, where an existing coal-fired power plant was repowered with IGCC. Repowering the plant resulted in a reduction in emissions of CO_2 from 0.64 lbs/MWh to 0.55 lbs/MWh, a 14% decrease.

Potential Reductions in CO_2 Emissions from Existing Plants
Given the size of efficiency increases that are currently available from either retrofitting individual technologies or repowering existing plants, significant reductions in CO_2 can be realized on the existing fleet of coal-fired capacity. The National Coal Council's 2001 report noted that 75% of existing plants could easily retrofit one or more technologies to enhance boiler and/or steam turbine efficiency. The report also noted that 25% of the existing units could be repowered with a CCT. Assuming a 5% increase in efficiency on 75% of existing plants (from efficiency enhancements), and a 17% increase on the other 25% (from repowering with existing IGCC technology), an overall 8% increase in efficiency of today's coal-fired generating plants could be accomplished. This would result in a proportional 8% decrease in emissions, including CO_2.

3.2 CO_2 Capture Technology

3.2.1 Summary

Processes for removing CO_2 from flue gas or syngas can be classified in terms of the subject gas stream's pressure and the partial pressure of CO_2 within the gas stream. Typically, low-pressure processes are applied to combustion sources and high pressure to IGCC sources of CO_2.

Low total and CO_2 partial pressure gas streams are predominantly flue gases from power plants, refinery off gases, and industrial boiler flue gases. High total and CO_2 partial pressure gas streams are less common, with the primary example being syngas from IGCC plants. Technologies used for capture of CO_2 and other gases, used in other industries, may be able to be applied to coal-based power plants for CO_2. Much work remains to be done to determine how to integrate these technologies into both combustion-based and IGCC plants. Even with sufficient R&D to make these technologies commercially available, capital and O&M costs will be significant, as will impacts on power plant efficiency.

3.2.2 Technology for Coal Combustion Applications

Conventional processes for CO_2 separation/removal from multi-component gaseous streams at atmospheric pressure include:

- chemical absorption;
- physical absorption;
- adsorption;
- gas permeation (i.e., selective membranes); and
- cryogenic cooling or cryogenic-supported absorption.

Chemical absorption is the most common of these, most frequently using organic chemical absorbents such as monoethanol amine (MEA), di-ethanol amine (DEA), methyl di-ethanol amine (DMEA), tert-ethanol amine (TEA), and 2 amino-2-methyl-1-propanol (AMP). Alkaline compounds such as sodium hydroxide, potassium carbonate, and sodium carbonate are also used.

The CO_2 that is absorbed is then removed by either raising the temperature or lowering the pressure of the amine solution to desorb CO_2. The liberated CO_2 stream usually contains small amounts of H_2S and other acidic gases, and may require further cleanup before compression and transportation to an end user or to a sequestration site.

The chief drawbacks of amine-based processes are their limited absorption and the significant amount of energy necessary to release the captured CO_2. Typically, one pound of low-pressure steam is required to liberate one pound of absorbed CO_2. Thus, the absorber and stripper towers are large and require very large amounts of heat to regenerate the amines. Amine-based systems also require large pumps to circulate liquid absorbents and heat exchangers to manage the heat released in the process, as well as large compressors that raise the flue gas pressure to 15-30 psi to compensate for the pressure drop in the absorber tower.

Physical absorbents, such as methanol, dimethyl ether of polyethylene glycol (Selexol), and other organic sorbents, dissolve CO_2 without chemical reaction. These fluids are most often used in IGCC plants where CO_2 pressure is high, and are candidates for treating flue gases from coal combustion sources. CO_2 liberation and solvent regeneration are accomplished by pressure swings or temperature swings. High cost is the primary drawback of physical absorbent technologies for PC units.

Adsorption-based CO_2 removal processes are based on the significant intermolecular force between gases and the surface of certain solid materials, such as activated carbon. The adsorbents are usually arranged as packed beds of spherical particles. Either pressure or temperature swings are employed to capture and release CO_2 in a cyclic adsorption/desorption sequence.

Adsorption processes are used commercially for CO_2 removal from industrial steam-based natural gas reformers. While they are relatively simple, the CO_2 loading and selectivity of available adsorbents is low. Since flue gas is at atmospheric pressure, some compression is necessary, particularly with pressure swing desorption. Very high CO_2 purity is obtained, but overall costs are high. Activated carbon or carbon molecular sieves would be the likely adsorbents used for CO_2 removal from PC units.

Gas separation membranes operate on the principle that porous structures permit the preferential permeation of certain gas stream components. The primary design and operational parameters for membranes are selectivity and permeability. Permeability is the major limiting factor for membranes used to remove CO_2 from flue gas, which means very large surface areas are necessary and, thus, costs are high. In order to provide an adequate driving force, the flue gas must be compressed to at least 50 psi. A two-stage separation system may be required to effectively remove CO_2 from flue gas, at about twice the cost of amine-based systems.

Gas absorption membranes consist of microporous solid membranes in contact with an aqueous absorbent. In a common arrangement, called membrane-assisted absorption, CO_2 diffuses through the membrane and is then absorbed by MEA. The equipment for this process tends to be more compact than that for conventional membrane systems. Since the captured CO_2 is in the liquid phase, it can be cost-effectively pumped to high pressure for discharge from the plant or to a sequestration site. Membrane-assisted absorption costs are comparable to that for conventional MEA absorption. Further R&D might identify a more optimal membrane/absorber coupling, improving the economics.

Cryogenic separation of flue gas constituents involves compressing and cooling the flue gas in stages to induce phase changes in CO_2 and other gases. Although cryogenic processes can lead to high levels of CO_2 recovery, the processes are very energy intensive. The cost of cryogenic CO_2 removal may not be significantly higher than for amine absorption processes.

3.2.3 Technology for Gasification Applications

Removing concentrated CO_2 from IGCC syngas, which is usually at pressures from 300-1,000 psi, allows a broader range of process options than does removal from atmospheric-pressure flue gas. As a consequence, the costs per ton of CO_2 removed from IGCC power plants are lower than for PC plants (primarily due to the higher concentration in IGCC syngas than in PC plant flue gas). Cost reductions and performance improvements for “high pressure” CO_2 removal systems are still necessary to approach the goals of DOE’s Vision 21 and the recently announced FutureGen program.

Because virtually all CO_2 control options for IGCC plants involve removal prior to syngas combustion, effective overall plant CO_2 reductions require operation of the gasifier in a "steam shifted" mode to produce less CO (which would oxidize to CO_2 in the gas turbine combustor) and more H_2 and CO_2. Although "shifting" leads to reduced power output, higher CO_2 partial pressures substantially improve CO_2 separation process performance.

CO_2 removal process candidates for IGCC plants are:

- selective physical absorption using an organic fluid such as methanol, with desorption by low-pressure steam;
- physical adsorption on activated carbon, with CO_2 regeneration by pressure swing;
- selective polyamide or ceramic membranes for CO_2 separation;
- cryogenic distillation; and
- CO_2 hydrate separation.

The most analyzed and practiced high-pressure CO_2 separation processes involve ***physical absorption*** with Selexol, Rectisol (low-temperature methanol), propylene carbonate, or other organic working fluids. CO_2 is liberated and the solvent regenerated at relatively low pressures (15-30 psi). Because the gas stream to be treated does not require compression, and because extensive heating is not required to regenerate the solvent, physical absorption processes for gasification power plants are much less energy-intensive than low-pressure processes for PC plants. However, even this lower rate of parasitic energy demand is still costly.

Adsorption processes for removing CO_2 from gasifier synthesis gas are functionally similar to those for treating flue gas. The adsorption/desorption processes are cyclic, with the most common desorption approach being pressure swing. The two main concerns being investigated by researchers are: (a) the selectivity of adsorbents to capture only CO_2, and (b) low-surface adsorbing capacity for CO_2, requiring large, costly contact areas.

Gas separation membranes have been widely explored for CO_2 capture from high-pressure synthesis gas as well as from flue gas. Membrane separation of CO_2 from light hydrocarbons has been very successful in the oil and gas industry because of its simplicity of operation, absence of moving parts, and modular construction. The main disadvantages are the limitations in CO_2 flow through the membrane and the large CO_2 pressure drop necessary to effect separation. A new class of high-temperature, high-pressure "ion transport membranes" is being developed, which may enhance the performance of membrane processes. Most of the effort associated with this research is, at present, focused on O_2 separation from air, but it may also be a promising research field for CO_2 separation.

Cryogenic separation of gas mixtures involves cooling in stages to induce selected phase changes in constituents, including CO_2. For syngas, however, water vapor in the gas stream could lead to formation of solid CO_2 hydrates and ice, which with solid CO_2 can cause major plugging problems. Because cryogenic processes are inherently energy intensive, their use for CO_2 removal in IGCC plants will constitute a major parasitic load.

CO_2 hydrate separation processes are designed to produce CO_2 clathrates in high-pressure, multi-component gaseous streams to selectively remove CO_2 and H_2S. In the SIMTECHE process, syngas (generated by a gasifier operating in a shift mode) is cooled to about 35°F and contacted with a nucleated water stream to form a CO_2/H_2S hydrate slurry. The remaining gas, containing primarily H_2 (and also N_2 if using an air-blown gasifier), is separated from the hydrate slurry in a gas/liquid separator. The CO_2/H_2S hydrate slurry can be decomposed in a "flash reactor." Performance and economic analyses suggest that this process may be substantially less energy intensive and less costly than established processes for extracting CO_2 from shifted synthesis gas and compressing it for transportation. New organic salt "promoters" have been identified, which could enable very high CO_2 separation rates. These compounds are highly soluble in water and could permit CO_2 hydrate formation at temperatures as high as 75-85°F and with low CO_2 partial pressures. Operation under these conditions should reduce both parasitic power losses and cost.

3.3 Non-CO_2 GHG Emission Reductions

3.3.1 Methane

Methane is the second most important non-water GHG, with a Global Warming Potential (GWP) 21 times as great as that of CO_2 on a mass basis, assuming a 100-year time horizon. Coal mine methane (CMM) is one of several major sources of anthropogenic methane, accounting for about 10% of anthropogenic methane emissions in the U.S. CMM is responsible for about 1% of the total GWP of all U.S. anthropogenic GHG emissions.

The total volume of CMM liberated from active mines in the U.S. in 2000 was 187 billion cubic feet. Underground mining activities alone liberated 134 Bcf of CMM (72% of U.S. total CMM). A substantial part of the CMM liberated from underground mining is recovered for use rather than being emitted. Other sources of liberated CMM include surface mines and post-mining activities (e.g., coal storage, processing, and transportation). Methane from abandoned coal mines is called abandoned mine methane (AMM), and for current purposes is considered separately from CMM. During 2000, 11.5 Bcf of AMM was liberated, with a fraction of that recovered for use. Coal bed methane (CBM) that is produced strictly for sale into natural gas pipelines (i.e., not in association with coal mining activities) is not addressed in this discussion. Table 3-4 summarizes the amounts of CMM and AMM liberated, recovered, and emitted in the U.S. in 2000.

Table 3-4. Relevant Data of U.S. CMM and AMM for 2000.

Category	Quantity, Bcf
Active Mines (CMM)	
CMM liberated	187
CMM emitted	151
CMM recovered	36
Underground mine CMM liberated	134
Underground mine CMM drained	45
Underground mine CMM drained and recovered	36
Underground mine CMM drained and emitted	9
Underground mine ventilation air methane	89
Underground mine CMM emitted	98
Abandoned Mines (AMM)	
AMM Liberated	11.5
AMM Recovered	2.5
AMM Emitted	9
Total Active Plus Abandoned Mines	
CMM + AMM liberated	198.5
CMM + AMM recovered	38.5
CMM + AMM emitted	160
Note: *This table does not consider CBM obtained solely for injection into natural gas pipelines or CBM not produced in association with coal mining.*	

Types of CMM

Methane is liberated from underground coal mines either in advance of mining, during mining activities, or after mining has occurred. The liberated methane exits the mine through drainage (degasification) systems or mine ventilation systems. In the case of abandoned underground mines, the liberated methane exits through vents or drainage systems.

When liberated in advance of mining, methane is drained through vertical boreholes drilled into the coal seam much as in conventional natural gas production. This type of CMM recovery often occurs years ahead of the mining activity. CMM that is drained in advance of mining is also considered to be coalbed methane, or CBM. This methane is often of very high quality, and acceptable for injection into natural gas pipelines. Horizontal boreholes are sometimes used for degasification in advance of, but near the time of, mining. This process often produces high-quality gas that can be recovered. However, its recovery is frequently impractical and much of this gas is emitted through boreholes to the surface or with the ventilation air.

After coal is extracted in a longwall type of underground mine, the methane can be released into the mine to mix with the ventilation air or it can be drained through vertical wells. This CMM can be of pipeline quality; however, it is often contaminated with air and must be processed prior to being injected into the pipeline.

Ventilation air is another source of methane emissions from underground coal mines. Air is drawn through underground mines, to provide a breathable atmosphere and to dilute the liberated methane to concentrations usually below 1% for safety reasons. The ventilation air mixes with liberated methane and the mixture is exhausted into the atmosphere.

Recovery of CMM and AMM for Use

The U.S. coal industry has made substantial progress in recovering and using CMM though drainage systems. Of the 134 Bcf of CMM liberated from underground mines in 2000, 45 Bcf was liberated through drainage systems. The remainder, 89 Bcf, was emitted as ventilation air. U.S. industry recovered 36 Bcf (or 80%) of the CMM liberated through drainage systems in 2000. This recovery represents an almost three-fold increase from the 13.8 Bcf recovered in 1990. The unrecovered CMM from drainage systems (9 Bcf per year) is generally low- to medium-quality gob gas or stranded gas.

During 2000, the methane liberated from underground mines but not recovered included 9 Bcf of low-quality or stranded drained gas and 89 Bcf of ventilation-air methane (VAM). VAM is the single largest source of unrecovered CMM. Although VAM is a potential fuel resource, essentially 100% of it is emitted because its capture and use is difficult due to its low methane concentration (typically 0.3% to 1.5%). This concentration is too low for use in even the most lean-burning of available combustion systems that require methane concentrations of 2% or more. The utilization of VAM currently is limited to a few isolated cases in which it can be used as combustion air in fossil-fuel-fired power plants located at the ventilation fan.

An estimated 2.5 Bcf (22%) of the 11.5 Bcf of liberated AMM was recovered for use in 2000. The total CMM plus AMM recovered in 2000 (38.5 Bcf) represents a resource of approximately 0.4 quadrillion Btu of fuel energy, and the avoided emissions are equivalent in GWP to the emission of approximately 17 $MTCO_2$ (see Table 3-5 for equivalencies). This amount of energy is much greater than the fuel plus electricity consumption of the entire U.S. coal mining industry, which was only about 0.1 quadrillion Btu in 1997. In the event that it becomes desirable to reduce coal-mining GHG emissions, it will be important to maintain and expand the recovery of CMM and AMM.

Table 3-5. Selected Equivalencies.

1 Bcf of methane	~ 21,085 short tons of methane
	~19,128 metric tonnes of methane
	~ 1.010 X 10^{12} Btu (HHV)
	~ 442,785 short tons of CO_2 GWP equivalent
	~ 120,760 short tons of carbon GWP equivalent
	~ 401,688 metric tonnes of CO_2 GWP equivalent
	~ 109,551 metric tonnes of carbon GWP equivalent

Currently, the recovery of CMM is driven by two factors: the resulting improvement in mining conditions and the value of the gas. Most of the recovered CMM is used as pipeline-quality gas, but smaller quantities are used at qualities not meeting pipeline specifications and some is used as combustion air. Technologies under development, including ultra-lean-burn turbines and methane concentration systems could expand the options available for CMM recovery and use. Future GHG reduction requirements, in conjunction with advanced recovery technologies, could easily result in increased recovery of CMM. Further development and demonstration of additional recovery and use options for CMM and AMM is recommended.

Table 3-6. 1997 Energy and Fuel Consumption by U.S. Coal Mining Industry.

Fuel or Energy	Lignite & Bituminous Surface Mines[d]	Bituminous Underground Mines[d]	Anthracite Mines[d]	Total Coal Mines	Fuel energy, Btu/unit[e] (gross)	Energy consumption 1E+09 Btu (gross)	Energy consumption quads (gross)
Electricity purchased, MWh	4203672	7061319	89914	11354905	3.4121E+06	38745	
Distillate fuel, 1000 Bbl	7420.4	655.9	97.2	8173.5	5.8270E+09	47627	
Residual fuel, 1000 Bbl	721.8	144.8	35.8	902.4	6.1880E+09	5584	
Gas, bcf	0.7	0.5	D	1.2	1.0350E+12	1242	
Gasoline, million gal	29.4	4	0.3	33.7	1.2480E+11	4206	
Coal, 1000 ton [a]	31.5	221.4	D	252.9	2.4000E+10	6070	
Coal, 1000 ton [b]	D	D	0	0	2.4000E+10	0	
Total						103473	0.1035

Coal energy production in U.S. in 1997, quads[c]	23.211
Energy used to produce U.S. coal in 1997, quads[f]	0.1035
Parasitic energy consumption in 1997 for U.S. coal industry, %	0.446

D = not disclosed

(a) produced and used in same plant

(b) purchased

(c) source: U.S. Energy Information Administration, Annual Energy Review 2002.

(d) source: U.S. Economic Census, Mining Sector, EC97N-2121A, B, C, 1999.

(e) assumes electricity is 100% efficient, values for gross Btu/unit of fuels are author's estimate.

Conversion of CMM

Because the combustion of a given mass of methane to CO_2 and water reduces its GWP by 87%, it is possible to greatly reduce the GWP of the unrecovered CMM emissions by combustion (or more precisely, oxidation) even if the fuel value of the methane is not realized. For example, CMM of sufficient concentration could be combusted in a flare. This technique is being demonstrated at a coal mine in Australia. Alternatively, CMM of low concentration, such as VAM, could be oxidized in thermal or catalytic oxidation systems. Small-scale thermal oxidation systems have been operated on VAM in both Australia and Great Britain, and there are plans to demonstrate a small commercial-scale system in a coal mine in Pennsylvania as part of a public-private initiative by the DOE.

The 98 Bcf of CMM emitted in 2000 represents the equivalent GWP of 43 $MTCO_2$. Recovery and use (or oxidation) of these methane emissions may be an attractive means of reducing GHG emissions at relatively low cost. Further development and demonstration of CMM destruction and utilization options is recommended.

Projected Costs for Further Abatement of CMM Emissions

The EPA performed a marginal abatement cost analysis for CMM and AMM. That study projects that in the year 2005 and in the absence of carbon credits, it will be possible to economically capture and use 33% of the CMM plus AMM liberated from U.S. coal mines (66.6 Bcf out of 203.5 Bcf liberated in that year). This compares with the 19% actually captured and used in the year 2000. The percentages of the total liberated CMM plus AMM that could be reduced at various levels of carbon credits are shown in Table 3-7. For example, at carbon credit values of \$9.09/ton and \$18.20/ton (\$2.48/ton and \$4.96/ton of CO_2), EPA projects that it will be possible to economically increase the amount captured and used to 39% and 48%, respectively.

Table 3-7. Marginal Abatement Costs for CMM and AMM, Projected for the Year 2005

Credit Value \$/ton carbon	\$/ton CO_2	% reduction
0	0	33
9.09	2.48	39
18.20	4.96	48
27.27	7.44	55
45.45	12.40	60
90.90	24.80	64
181.81	49.59	65

In the table, "% reduction" refers to the percentage of the total CMM plus AMM liberated (projected to be 203.5 Bcf in 2005) that could be captured and used at the corresponding credit value. Values have been converted to standard tons of C and CO_2.

Source: U.S. Environmental Protection Agency, "Addendum to the U.S. Methane Emissions 1990-2020: 2001 Update for Inventories, Projections, and Opportunities for Reductions", downloaded from www.epa.gov/ghginfo/pdfs/final_addendum2.pdf, last modified February 20, 2002.

3.3.2 N_2O Emissions

Background

N_2O is a highly effective GHG, with a GWP 296 times that of CO_2. Because of its long lifetime (about 120 years) it can reach the upper atmosphere, depleting the concentration of stratospheric ozone, an important filter of UV radiation. Estimates of N_2O emissions from coal combustion globally are 0.2 Mt/year, approximately 2% of total known sources.

The origin of the small amount of N_2O emitted from coal combustion is the fuel nitrogen, released both during devolatilization and char combustion.[1,2] Maximum N_2O formation occurs at about 1350°F. As the temperature rises, N_2O is increasingly reduced to NO. As a result, only a negligible amount of N_2O (0.5-2.0 ppm in the flue gas) is emitted from high temperature (>2300°F) PC combustion.

N_2O Emissions From FBC

In optimum FBC operation, there is a conflict between the lower temperature favoring sulfur capture and the higher temperature required to reduce N_2O emissions. Typical N_2O emissions in the range of 40-70 ppm (at 3% O_2) result from operation at 1472-1562°F, the optimum temperature range for sulfur capture. At higher temperatures, $CaSO_4$, the product of sulfur capture, gradually decomposes and SO_2 is released.

An inventory of N_2O emissions from FBC is shown in Table 3-8.[4] It is noted that 60 ppm N_2O emission is equivalent to 1.8% CO_2, an increase of about 15% in CO_2 emission for an FBC boiler.

Table 3-8. N_2O Emissions from FBC (from IEA Coal Research [4])

Unit Size, MWe Hard Coal	N_2O Emissions, ppmv		O_2, %	Reference
	Mean	Range		
160	40	20-60	3-4	Brown and Muzio, 1991
110	70	40-100	3-4	Brown and Muzio, 1991
70	60	20-100	6	Bonn and others, 1993
50	70	40-100	6	Kimura, 1992
40	50	40-60	3-4	Boemer and others, 1993
24	52.5	45-60	1.5-2	Boemer and others, 1993
21	50.5		6	Vitovec and Hackl, 1992
21	69		3	EER, 1991
16	68	53-83	6	Sage, 1992
14	77.5		6	Vitovec and Hackl, 1992
13	45	20-70	6	Sage, 1992
11	28		6	Sage, 1992
6.7	70		6	Svensson and others, 1993
0.7	88	25-150	6	Hulgaard and Johansen, 1992

More research is needed to understand how fuel type, boiler operating conditions, post-combustion flue gas treatment, and pressure affect N_2O emissions. Qualitative effects of FBC operating parameters upon N_2O emissions are illustrated in Table 3-9.

Table 3-9. Effect of FBC operating parameters on N_2O emissions. (after Takeshita et al.[4])

Parameter increases	N_2O emissions
Temperature	↓↓
Excess air	↑
Air staging	↓
Boiler load	↓
Limestone feed	–
Coal rank	↑
Fuel N content	↑
SNCR-NH_3	↑
SNCR-Urea	↑↑
SCR	–
↑↑ emission strongly increases	
↑ emission increases	
↓↓ emission strongly decreases	
↓ emission decreases	
– no effect observed	

Possibilities for N_2O Control
Several techniques have been proposed to control N_2O emissions from FBC boilers. There have been several proposals that involve adjusting the combustion process to lower the N_2O emissions.[11,12] Since temperature is the strongest factor for N_2O reduction, many of these involve various staging techniques to achieve a higher temperature at the top or downstream of the combustion zone. This may be achieved by staging the air or by introducing additional fuel. For example, the temperature of the particle-free gas at the exit from the process cyclone can be raised by after-burning, but this may require about 10% natural gas to produce an effect of about 50% reduction.[5] Similar reductions achieved by afterburning with 10% ethane or propane injection were reported from laboratory studies.[13,14] Proprietary strategies to increase FBC combustion temperatures above the stability temperature of calcium sulfate have also been developed, and it has been proposed that various catalysts, structural or powdered, may be used in or following the combustion zone to reduce the N_2O emissions.[15] Further R&D is needed to find economically attractive solutions.

PFBC emits N_2O at somewhat lower levels, but N_2O can be strongly reduced at the elevated temperature in the topping combustor of the PFBCwTC cycle.[6]

Published N_2O Emission Factors
Published emission factors represent an average emission rate from a typical emission source and, therefore, on average are applicable to other similar emission sources. However, emission rates may vary with equipment size, efficiency, and vintage, as well as maintenance and operational practices. Applicability of an emission factor to a specific emission source requires

an understanding of the conditions associated with developing the emission factor or a measurement of potential bias -- information that may not be readily available.

Ideally, data quality is assessed through statistical analysis of accuracy and precision. EPA's AP-42 provides quality ratings for each of their emission factors. These are shown in Table 3-10 for the N_2O emission sources. A rating of "A" represents excellent quality data, meaning the factor is based on a large data set with a random pool of facilities in the population. Rating "B" represents above average quality, and "C" is average. A rating of "D" represents a factor with below-average quality, mainly resulting from limited data points or not having a random sample of the industry. A rating of "E" represents a poor quality factor, with a high degree of variability within the source category population.

Table 3-10. Comparison of Coal N_2O Emission Factors.

Combustion Technology	Equipment Configuration	IPCC Table 1-15, Volume 3 g N_2O/GJ (LHV)	IPCC Table 1-15, Volume 3 Converted to g N_2O/ GJ (HHV)	AP-42 Converted to g N_2O/ GJ (HHV)	AP-42 Reference Table, Year, and Quality Rating	% Difference (AP-42 vs. IPCC)
PC Bituminous	Dry Bottom, wall fired	1.6	1.5	0.5	Table 1.1-19, 9/98, E	206.2%
	Dry Bottom, tangentially fired	0.5	0.5	1.3		64.1%
	Wet Bottom	1.6	1.5	1.3		14.8%
Bituminous Spreader Stokers	With and without re-injection	1.6	1.5	0.7		129.7%
Bituminous FBC	Circulating Bed	96	91.2	57.9	Table 1.1-19, 9/98, B	57.5%
	Bubbling Bed	96	91.2	57.9		57.5%
Bituminous Cyclone Furnace		1.6	1.5	1.5	Table 1.1-19, 9/98, E	2.1%
Lignite AFBC		42	39.9	41.4	Table 1.7-4, 9/98, E	-3.6%

Early studies (prior to 1988) reported substantial levels of N_2O emissions from PC units, with levels proportional to NOx emissions. However, it was later determined that the high levels of N_2O measured were an artifact of the sampling procedure. Since 1988, measurement programs have utilized corrected sampling techniques and have measured much lower N_2O emission rates. The data cited in Table 3-8 for FBC are free from the sampling artifact, and current AP-42 emission factors in Table 3-10 also reflect these more recent results. N_2O emission values in Table 3-10 for PC and cyclone furnaces are small, their rating is poor (E), and the number of measurements is limited. In contrast, measurement data for FBC are of much higher value, and their ratings are also higher (B). When converted from to ppm (at 3% O_2), data for FBC give good agreement with those in Table 3-8.

The API GHG Emissions Workgroup, which developed the API Compendium, has begun a study of N_2O emission factors for stationary combustion sources. This study will compile additional N_2O emission measurements from an earlier API program, review literature for more recent studies, and gather data from participating petroleum companies.

The information will be evaluated to assess the quality and applicability of the emissions factors and to determine the relative contribution of N_2O emissions for different facility types. An assessment of emission factor quality or access to information from which to analyze emission factor quality is generally not available from published sources. It would benefit industry if DOE, in cooperation with EPA, were to improve AP-42 by increasing the number of N_2O emissions measurements for the different coal types and combustion technology combinations.

3.4 Carbon Sequestration

After carbon is removed from a flue or fuel gas stream, it must be "sequestered" or stored to avoid its emission into the atmosphere. While carbon capture technology is in commercial use in a number of industries, carbon sequestration technology is, except for a few relatively small-scale examples, unproven. The DOE Carbon Sequestration Program is developing a suite of technologies that have the potential to reduce GHG emissions from power generation. These systems could make a substantial contribution to efforts to meet GHG intensity goals. The availability of these systems as commercially proven technologies would be an important component of the decision-making process for any future actions taken to reduce GHG emissions.

Goals of the Carbon Sequestration Program

The NETL has summarized its vision and goals as follows (values converted to \$/ton CO_2 and standard tons):

Vision: Possess the scientific understanding of carbon sequestration options and provide cost-effective, environmentally sound technology options that ultimately lead to a reduction in GHG intensity and stabilization of overall atmospheric concentrations of CO_2.

Overarching Goals:

- By 2006, develop instrumentation and measurement protocols for direct sequestration in geologic formations and for indirect sequestration in forests and soils that enable the implementation of wide-scale carbon accounting and trading schemes.
- By 2008, begin demonstration of large-scale carbon storage options (>1 $MTCO_2$/year) for value-added (enhanced oil recovery, enhanced CBM recovery, enhanced gas recovery) and non-value-added (depleted oil/gas reservoirs and saline aquifers) applications.
- By 2008, develop (to the point of commercial deployment) systems for advanced indirect sequestration of GHGs that protect human and ecosystem health and cost no more than \$2.48 per ton of CO_2 sequestered, net of any value-added benefits.
- By 2010, develop instrumentation and protocols to accurately measure, monitor, and verify both carbon storage and the protection of human and ecosystem health for carbon sequestration in terrestrial ecosystems and geologic reservoirs. Such protocols should represent no more than 10% of the total sequestration system cost.
- By 2012, develop (to the point of commercial deployment) systems for direct capture and sequestration of GHG emissions from fossil fuel conversion processes that protect human and ecosystem health and result in less than a 10% increase in the cost of energy services, net of any value-added benefits.
- By 2015, develop (to the point of commercial deployment) systems for direct capture and sequestration of GHG emissions and criteria pollutant emissions from fossil fuel conversion

processes that result in near-zero emissions and approach a no net cost increase for energy services, net of any value-added benefits.
- Enable sequestration deployments to contribute to the President's GCCI goal of an 18% reduction in the GHG intensity of the U.S. economy by 2012.
- Provide a portfolio of commercial-ready sequestration systems and one to three breakthrough technologies that have progressed to the pilot test stage for the 2012 assessment under the GCCI.

Sequestration Technology

Several concepts for storage have been evaluated; however, technological and economic feasibility (and public acceptance) of carbon sequestration options vary depending on the locations of disposal sites and types of disposal/storage/sequestration technologies used. The capacity, effectiveness, and health and environmental impacts of various types of CO_2 disposal systems and the impacts of inadvertent releases are key areas of scientific uncertainty. Leading approaches to CO_2 storage presently include:

- Injection into deep saline aquifers or coal seams;
- Stimulation of oil and gas production;
- Disposal in depleted oil and gas reservoirs;
- Terrestrial sequestration (e.g., forestation, improved land-use practices);
- Growth of plants or algae for use as bio-fuels;
- Ocean sequestration; and
- Use as a feedstock for the manufacture of chemical products.

Potential Capacity of Sequestration Sinks

One of the most frequently asked questions related to carbon sequestration is that of storage capacity. While the conventional wisdom is that this capacity is quite large (i.e., 1000s of GtC[4] worldwide), the actual capacity is quite uncertain. This is because one first must estimate the total amount of void space available underground (or under water). Next, an estimate of what fraction of void space would be appropriate for CO_2 storage is required. For the first estimate (total void space), data are sparse. While many wells have been drilled, they have only revealed data on a small fraction of the underground. The second estimate (usable fraction) relies both on data about underground reservoirs (which data are sparse), as well as an understanding of how CO_2 would behave in these reservoirs. Despite these difficulties, estimates have been made, but there is no consensus on the numbers. It does seem safe to assume that the geologic storage capacity in the U.S. is over 100 GtC and could potentially be over 1,000 GtC. Several of the published estimates for the U.S. and the world are given below.

[4] 1 GtC = one billion (10^9) metric tons carbon. Note that 1 GtC = 3.67 $GtCO_2$. Also, current world anthropogenic carbon emissions are less than 7 GtC.

Table 3-11. The Worldwide Capacity of Potential CO_2 Storage Reservoirs.

Ocean and land-based sites together contain an enormous capacity for storage of CO_2[a].

The world's oceans have by far the largest capacity for carbon storage.

Sequestration option	Worldwide capacity[b]
Ocean	1,000 – 10,000+ GtC
Deep saline formations	100–10,000 GtC
Depleted oil and gas reservoirs	100 – 1,000 GtC
Coal seams	10–1,000 GtC
Terrestrial	10 - 100 GtC
Utilization	currently <0.1 GtC/yr

[a] Worldwide total anthropogenic carbon emissions are ~7 GtC per year (1 GtC = 1 billion metric tons of carbon equivalent).
[b] Orders of magnitude estimates.

Source: Herzog, H.J. and D. Golomb, "Carbon Capture and Storage from Fossil Fuel Use," contribution to Encyclopedia of Energy, to be published (2004).

Table 3-12. Worldwide Potential for CO_2 Sequestration.

Human activity	6 GtC/yr
Forest & Soils	> 100 GtC
Geologic	300-3200 GtC
Oceans	1400-20,000,000 GtC
Deep saline aquifers	10,000 – 200,000 GtC

Source: U.S. DOE Fossil Energy website (http://www.fe.doe.gov/coal_power/sequestration/); Bruant et.al., "Safe Storage of CO_2 in Deep Saline Aquifers," ES&T, pp. 241A-245A, June 1, 2002; IPCC Workshop on Carbon Capture and Storage, Regina, Canada, 18-21 Nov 2002. See http://www.climatepolicy.info/ipcc/ipcc-ccs-2002/index.html.

Table 3-13. U.S. Potential for CO_2 Sequestration.

Deep saline aquifers	**1-130 GtC**
Natural gas reservoirs	**25 GtC**
Active gas	**0.3 GtC/yr**
Enhanced coalbed methane	**10 GtC**

Source: U.S. DOE, "Carbon Sequestration Research and Development," Rpt # DOE/SC/FE-1 (1999). page 5-5

Table 3-14. U.S. potential for sequestration.

Depleted gas fields	690 GtC
Depleted oil fields/CO2-EOR	120 GtC
Deep saline aquifers	400-10,000 GtC
Unmineable coal seams	400 GtC

Source: IPCC Workshop on Carbon Capture and Storage, Regina, Canada, 18-21 Nov 2002. See http://www.climatepolicy.info/ipcc/ipcc-ccs-2002/index.html

These studies have shown that there is substantial potential for CO_2 storage in natural reservoirs, such as deep saline aquifers or in the deep ocean. While some have estimated that the storage/disposal process may be considerably less costly than the CO_2 capture process, large-scale carbon sequestration has yet to be demonstrated and significant uncertainty remains about the economic costs and environmental impacts of the site-specific applications described above. Such issues indicate a need for further research; collaborative programs are being developed to examine many of these topics.

Certain underground geologic formations exhibit structure, porosity, and other properties that render them suitable as potential CO_2 storage sites. These structures are ones that already have stored crude oil, natural gas, brine, and CO_2 over millions of years.

CO_2 injection is practiced at numerous sites worldwide for enhanced oil and natural gas recovery (EOR and EGR, respectively). However, in the current applications of CO_2 injection for EOR and EGR, processes have not been optimized for underground CO_2 disposal, and the long-term stability of the stored CO_2 remains unknown. Furthermore, political and siting issues must be addressed before any major quantity of CO_2 can be stored underground in this manner.

Long-term storage of CO_2 in geologic formations has the potential to be feasible in the near-term. Many power plants and other large point sources of CO_2 emissions are located near geologic formations that may be amenable to CO_2 storage. Saline formations do not contain oil and gas resources and thus do not offer the value-added benefits of enhanced hydrocarbon production. However, the potential CO_2 storage capacity of domestic saline formations is enormous; estimates are on the order of several hundred years of CO_2 emissions.

The primary goal of research in this area is to better understand the behavior of CO_2 when it is stored in geologic formations in order to ensure secure and environmentally acceptable storage of CO_2. The fastest and surest means of obtaining the necessary information is to conduct field tests in which a relatively small amount of CO_2 is injected into a formation, with its fate and transport under close monitoring. The DOE program includes several such field tests, which ultimately should provide industry with tools and techniques to measure the movement of CO_2 in underground formations. These tests will provide field protocols that preserve the integrity of geologic formations.

Research and Development Requirements for CO_2 storage

1. Geologic Sequestration

   Unmineable coal seams
   - Coal seams that are unmineable for economic or technical reasons (e.g., depth or reserve characteristics) are potential CO_2 storage sinks.
   - Existing recovery technologies should be used to evaluate the feasibility of storing CO_2 in unmineable coal seams for commercial-scale field demonstrations.
   - The knowledge gained to verify and validate gas storage mechanisms in coal seams can be used to develop a screening model to assess CO_2 storage potential.

   CBM production
   - Carbon dioxide injection may be used to stimulate methane production from coal seams, improving the economic attractiveness of this sequestration option.
   - A broad-based geologic screening model should be developed to quantify the CO_2 storage potential in CBM regions and apply the model to identify additional sites with high CO_2 storage potential.

   Depleted oil reservoirs
   - Research is needed to investigate down-hole injection of CO_2 into depleted oil reservoirs and conduct computer simulations, laboratory tests, field measurements, and monitoring efforts to understand the geomechanical, geochemical, and hydrogeologic processes involved in CO_2 storage.
   - These observations could be used to calibrate, modify, and validate modeling and simulation needs.

   Carbon storage in geologic formations
   - Geologic sinks, such as deep saline reservoirs, represent some of the largest potential sequestration sinks.
   - The capacity and availability of these potential sinks needs to be quantified.
   - Research is needed to investigate safe and cost-effective methods for geologic sequestration of CO_2.
   - Research is needed on the siting, selection, and longevity of optimal sequestration sites to lowering the cost of geologic storage.
   - Monitoring techniques need to be identified and demonstrated which are cost-effective for tracking the potential for CO_2 migration in storage.

2. Terrestrial Approaches

Carbon sequestration in terrestrial ecosystems is either the net removal of CO_2 from the atmosphere or the prevention of CO_2 net emissions from the terrestrial ecosystems into the atmosphere. The terrestrial biosphere is estimated to sequester large amounts of carbon (approximately 2 billion metric ton of carbon per year). There are two fundamental approaches to sequestering carbon in terrestrial ecosystems:

(1) Protection of ecosystems that store carbon; and
(2) Management of ecosystems to increase carbon sequestration.

Research is under way to evaluate these approaches for the following ecosystems, which offer significant opportunity for carbon sequestration:

- Forest lands, including below-ground carbon and long-term management and utilization of standing stocks, understory, ground cover, and litter.
- Agricultural lands, including crop lands, grasslands, and rangelands, with emphasis on increasing long-lived soil carbon.
- Biomass croplands related to biofuels.
- Deserts and degraded lands in both below-and above-ground systems.
- Boreal wetlands and peatlands including management of soil carbon pools and conversion to forest or grassland.

3. Ocean storage

The oceans are the ultimate natural sink for CO_2 and may have potential for long-term CO_2 storage, but the environmental impacts of ocean sequestration are not adequately understood and the acceptability of empirical tests is problematic, given environmental sensitivity to marine systems. If ocean sequestration is to be accepted by the public, certain key questions must be answered.

- How well can the performance of storage be predicted?
- What will be the environmental impacts?
- Can such systems be successfully engineered?
- How can legal and jurisdictional obstacles be overcome?
- What will be the public acceptance of this idea?

4. Utilization of CO_2

Captured CO_2 could also be used for commercial purposes, such as a feedstock from which to derive chemicals. If economically feasible, such applications would offer the co-benefits of sequestering this GHG and replacing the use of other, manufactured feedstocks. CO_2 already is used for a wide range of applications in the food and petroleum industries, although in most cases the gas is not permanently stored in final products but is released to the atmosphere at a later date. The income generated from the sale of CO_2 would help to offset the cost of capturing and cleaning the gas. Significant costs would be incurred in producing chemical products and such processes generally require the input of energy, resulting in the emission of additional CO_2 if this energy is generated from fossil fuels.

The utilization of CO_2 to make chemicals is only effective as a mitigation option if, overall, less CO_2 enters the atmosphere than would otherwise have been the case. Also, the direct use of CO_2 to grow algae in order to make bio-fuels might be feasible, but only under certain conditions and in specific locations. A similar conclusion has been reached about the growth of crops to produce liquid fuels, which currently remains only an option for discussion.

Status of Carbon Capture and Sequestration Research

Funding provided by the DOE and the private sector for carbon capture sequestration research has increased considerably since the first National Coal Council report on this subject in May 2000. In FY 2002, the DOE carbon sequestration budget was around $8 million. By FY 2003, this had been increased to $42 million. As of October, 2002, the DOE/FE portfolio included 104 projects, with a total value of $162 million, with about 40% directed to carbon capture, and 60% to sequestration. Of this total, DOE funds $96 million. Significantly and importantly, the non-federal cost share ($66 million) represents 40% of the total, demonstrating a willingness on the part of private industry to invest in research partnerships to develop capture and sequestration technology, despite the uncertain need for and timing of its eventual application. Four of these research partnerships are described below.

Dakota Gasification Project (Weyburn).
The Weyburn Carbon Dioxide Sequestration Project is a $27-million research project intended to expand the knowledge of the capacity, transport, fate, and storage integrity of CO_2 injected into geological formations located in southeastern Saskatchewan, near the U.S. border with North Dakota. DOE will support this project by funding $4 million over a three-year period. The knowledge obtained from this project will enable DOE to inform public policy makers, energy industries, and the general public by providing reliable information and analysis of the geological sequestration of CO_2.

Sequestration of Carbon Dioxide in an Unmineable Appalachian Coal Seam.
Unmineable coal seams offer large, permanent storage potential for geologic sequestration of CO_2. These coal seams also represent an opportunity to sequester CO_2 while enhancing the production of coalbed methane as a value added product. CONSOL Energy is performing a seven-year R&D project to evaluate the effectiveness and economics of carbon sequestration in an unmineable coal seam in tandem with enhanced coalbed methane production. This project is a Cooperative Agreement at a total cost of $9.2 million with a 24% industry cost share.

Research and Commercial-Scale Field Demonstration for CO_2 Sequestration and Coalbed Methane Production.
In 2001, DOE awarded a $5.9 million, 70% cost-shared cooperative agreement with Advanced Resources International, BP Amoco, and Shell Oil for demonstrating existing and evolving recovery technology to evaluate the viability of storing CO_2 in deep, unmineable coal seams in the San Juan Basin in northwest New Mexico and southwestern Colorado. The knowledge gained with this demonstration effort will be used to verify and validate gas storage mechanisms in deep coal reservoirs, and to develop a screening model to assess CO_2 sequestration potential in coalbeds in the U.S.

The DOE has established a website listing all DOE-supported capture and sequestration projects (as of October 2002) and providing links to similar sites containing information on carbon sequestration research throughout the federal government and internationally. Current DOE projects are listed in Table 1 in Appendix A of this document. These project span a wide range of topics relevant to carbon capture and sequestration, including:

Separation and Capture
- Pre-combustion decarbonization
- Oxygen-fired combustion
- Post-combustion capture
- Advanced integrated capture systems
- Crosscutting science

Geologic Sequestration
- Monitoring, verification and remediation
- Health, safety and environmental risk assessment
- Knowledge base and technology for storage reservoirs

Terrestrial Sequestration
- Productivity enhancement
- Ecosystem dynamics
- Monitoring and verification

Ocean Sequestration
- Ecosystem dynamics
- Measurement and prediction
- Direct injection
- Ocean fertilization

Novel Sequestration Systems
- Biogeochemical processes
- Mineral conversion
- Novel integrated systems

3.5. GHG Management and the "Hydrogen Economy"

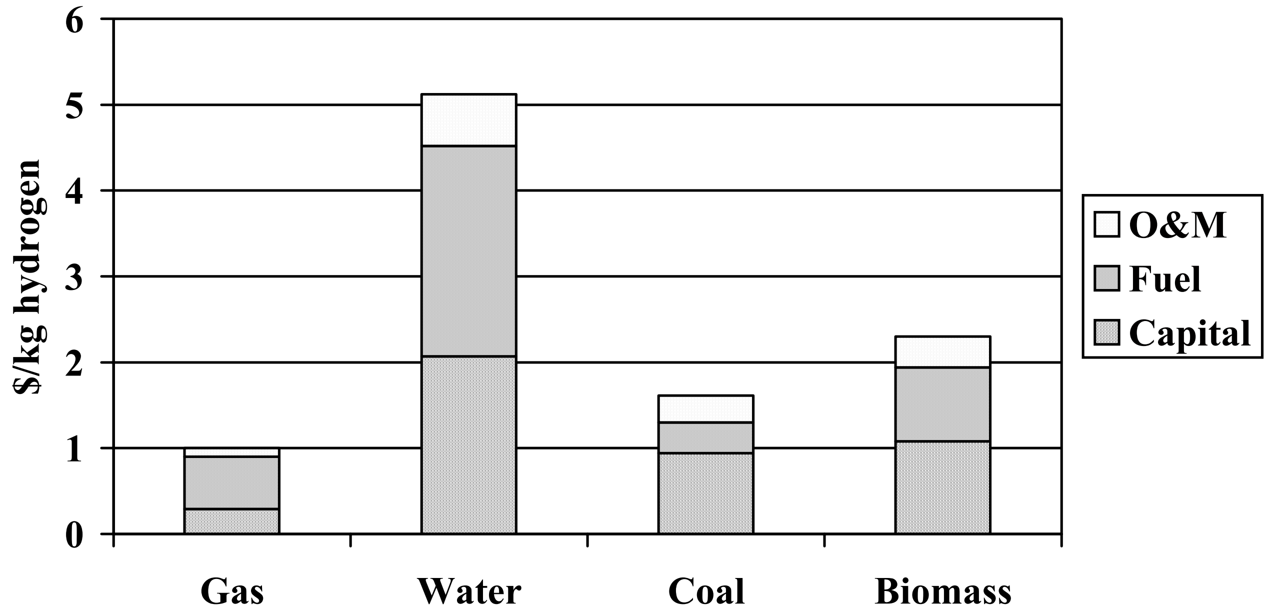
Hydrogen is called by many "the fuel of the future." However, it is important to realize that hydrogen is *not* a primary energy source like coal, oil, natural gas, wind, solar, biomass, hydro, nuclear, etc. Instead, like electricity, it is an energy carrier. As a result, hydrogen must be produced from the same array of primary energy sources that we use to produce electricity. Therefore, hydrogen is not in direct competition with coal as a fuel, but presents an opportunity to develop a new market for coal as a major feedstock for hydrogen production.

Figure 3-8 shows costs for the production of hydrogen from four possible sources: gas, coal, biomass, and water (via electrolysis).[5] This case assumes a central plant design of 165 ton/day of hydrogen with compression of the product to 1,100 psi, suitable for pipeline transportation. Costs of transmission and distribution are not included in this figure. Hydrogen is produced from natural gas by steam reforming, from coal and biomass by gasification, and from water by

[5] Data from Simbeck and Chang, Hydrogen Supply: Cost Estimate for Hydrogen Pathways – Scoping Analysis, NREL/SR-540-32525 (July 2002).

electrolysis (electricity is from the grid). Gas prices used were $3.50 per MBtu and coal prices were $1.10 per MBtu.

Figure 3-8. Hydrogen Production Costs



At relatively low natural gas prices, the lowest-cost hydrogen is produced from a natural gas feedstock, as is the case today in much of the commercial marketplace. However, the break-even price is very sensitive to natural gas cost. Other studies indicate an even lower break-even price for hydrogen from coal (at a gas price of $3.15-$4.00/MMBtu for gas, compared to $1.00/MMBtu for coal). At the time of this report, the forward curve for gas did not go below $4.00/MMBtu for any time that is currently traded. Therefore, if gas prices remain high or rise in the future (or gasification technology becomes less costly), coal is or would become the lowest cost feedstock. This is one of several similarities that can be drawn between hydrogen production and electricity production. It should also be noted that producing hydrogen from electrolysis is very expensive when compared to other options.

The cost and energy penalties for CO_2 capture from hydrogen production via gas, coal, or biomass are relatively small. This is because to produce hydrogen from hydrocarbon feedstocks, the capability to remove CO_2 is an integral part of the process. On the other hand, for CO_2-free hydrogen production from electrolysis, one must use CO_2-free sources of electricity. Since these are significantly more expensive than the current fuel mix, one can expect that hydrogen costs will grow significantly from those indicated in Figure 3-8. In the case of producing CO_2-free hydrogen, the advantage for using coal or gas will be even greater than the differential shown in Figure 3-8.

Just as coal plays a major role in the production of electricity, it has the potential to do the same for hydrogen. The added costs for CO_2 capture and storage will be significantly lower for hydrogen production than for electricity production. Since gasification is the preferred route of producing hydrogen from coal, implementing gasification technologies will position coal to take advantage of this potential new market should a hydrogen economy evolve.

3.6 International R&D Partnerships

3.6.1 Bush Administration Climate Change Policy

President Bush's climate plan announced on February 14, 2002, consists of long-term and short- to medium-term components. One component is a stated goal to "promote new and expanded international policies to complement the domestic program." The President's plan specifically cites the following examples of international cooperation:

- Investing $25 Million in Climate Observation Systems in Developing Countries. In response to the National Academy of Sciences' recommendation for better observation systems, the President has allocated $25 million and challenged other developed nations to match the U.S. commitment.
- Tripling Funding for "Debt-for-Nature" Forest Conservation Programs. Building upon recent Tropical Forest Conservation Act (TFCA) agreements with Belize, El Salvador, and Bangladesh, the President's FY '03 budget request of $40 million to fund "debt for nature" agreements with developing countries nearly triples funding for this successful program. Under TFCA, developing countries agree to protect their tropical forests from logging, avoiding emissions and preserving the substantial carbon sequestration ability therein. The President also announced a new agreement with the Government of Thailand that will preserve important mangrove forests in Northeastern Thailand in exchange for debt relief worth $11.4 million.
- Fully Funding the Global Environmental Facility (GEF). The Administration's FY '03 budget request of $178 million for the GEF is more than $77 million above this year's funding and includes a substantial $70 million payment for arrears incurred during the prior administration. The GEF is the primary international institution for transferring energy and sequestration technologies to the developing world under the UNFCCC.
- Dedicating Significant Funds to the U.S. Agency for International Development (USAID). The President's FY '03 budget requests $155 million in funding for USAID climate change programs. USAID serves as a critical vehicle for transferring American energy and sequestration technologies to developing countries to promote sustainable development and minimize their GHG emissions growth.
- Pursue Joint Research with Japan. The U.S. and Japan continue their High-Level Consultations on climate change issues. Later this month, a team of U.S. experts will meet with their Japanese counterparts to discuss specific projects within the various areas of climate science and technology, and to identify the highest priorities for collaborative research.

- Pursue Joint Research with Italy. Following up on a pledge of President Bush and Prime Minister Berlusconi to undertake joint research on climate change, the U.S. and Italy convened a Joint Climate Change Research Meeting in January, 2002. The delegations for the two countries identified more than 20 joint climate change research activities for immediate implementation, including global and regional modeling.

- Pursue Joint Research with Central America. The U.S. and Central American Heads of Government signed the Central American-United States of America Joint Accord (CONCAUSA) on December 10, 1994. The original agreement covered cooperation under action plans in four major areas: conservation of biodiversity, sound use of energy, environmental legislation, and sustainable economic development. On June 7, 2001, the U.S. and its Central American partners signed an expanded and renewed CONCAUSA Declaration, adding disaster relief and climate change as new areas for cooperation. The new CONCAUSA Declaration calls for intensified cooperative efforts to address climate change through scientific research, estimating and monitoring GHGs, investing in forestry conservation, enhancing energy efficiency, and utilizing new environmental technologies.

3.6.2 Bilateral Partnerships

Since its climate change policy was announced, the Bush Administration has also announced a number of bilateral partnerships (*see* Table 3-15) focused on collaborative efforts meant to address climate-related issues. Examples of opportunities for cooperation that may result in significant GHG reductions include, but are not limited to, CCT and CO_2 capture and storage technology development, expanded use of cogeneration and renewable sources of energy, as well as concrete ways of reducing GHG emissions through sustainable agriculture and forestry management practices.

Recommendation
Current efforts at forming bilateral partnerships are important steps in addressing the policy issue of global climate change. However, absent in most of the agreements is a particular emphasis on identifying opportunities to pursue collaborative CCT and CO_2 capture and storage technology development projects. In recognition of its vast U.S. coal reserves, the DOE has been one of the world's major funders of carbon sequestration RD&D. It is of vital importance that the U.S. now engage other nations in funding new CCT RD&D and pursue policies advocating upgrades or replacement of older coal-fired power stations around the globe with newer, more efficient technologies.

The DOE, acting as a principal agent of the U.S. within the bilateral partnerships, should perform the role of information clearinghouse on the partnerships' various efforts to develop CCT and CO_2 capture and storage technology development projects. Such a role could be accomplished by enhancing the existing materials on the agency's website (http://www.fe.doe.gov/international).

TABLE 3-15		
Date	**County**	**Partnership Agreement Details**
July 19, 2001	Italy	Pledge joint research in several critical areas, including: − atmospheric studies related to climate − low-carbon technologies − global and regional climate modeling − carbon cycle research
Feb. 27, 2002	Australia	Focus will be on such issues as: − emissions measurement and accounting − climate change science − stationary energy technology − engagement with business to create economically efficient climate change solutions − agriculture and land management − collaboration with developing countries to build capacity to deal with climate change
Feb. 28, 2002	Japan	The Partnership's priority research areas include: − improvement of climate models making use of the "Earth Simulator" and research on earth processes for modeling − impact and adaptation/mitigation policy assessment employing emission-climate-impact integrated models − observations and international data exchange/quality control − research on greenhouse gas (GHG) sinks including LULUCF (land use, land-use change and forestry) − research on polar regions − development of mitigation and prevention technologies such as separation, recovery, sequestration and utilization of carbon and GHGs − research and development of renewable and alternative energy technologies, resources, and products, as well as energy efficiency measures and technologies
Mar. 7, 2002	Canada	Both countries have agreed to pursue increased bilateral cooperation that will focus on such issues as: − climate change science and research − technology development − carbon sequestration − emissions measurement and accounting − capacity building in developing countries − carbon sinks − targeted measures to spur the uptake of cleaner technology and market-based approaches
May 6, 2002	India	The two sides announced their intention to enhance ongoing collaborative projects in: − clean and renewable sources of energy − energy efficiency − energy conservation

Date	Country	Partnership Agreement Details
Oct. 24, 2002	New Zealand	Themes for potential enhanced cooperation might include: – climate change science and monitoring in the Pacific; – assistance to developing countries, particularly Pacific Island states – climate change research in Antarctica – cooperation in the development of emission unit registries – GHG accounting in forestry and agriculture – technology development aimed at carbon reduction technologies
Jan. 16, 2003	China	The U.S. and China identified 10 areas for cooperative research and analysis: – non-CO_2 gases – economic/environmental modeling – integrated assessment of potential consequences of climate change – adaptation strategies – hydrogen and fuel cell technology – carbon capture and sequestration – observation/measurement – institutional partnerships – energy/environment project follow-up to the World Summit on Sustainable Development (WSSD) – existing clean energy protocols/annexes
Jan. 17, 2003	Russia	– Discuss and exchange information related to climate change policy and related scientific, technological, socioeconomic, and legal issues of mutual concern and interest. – Explore possible common approaches to addressing climate change issues before the United Nations Framework Convention on Climate Change, the Intergovernmental Panel on Climate Change, and other relevant international arenas. – Identify and encourage needed climate change science and technology research that is or could be performed individually or jointly by U.S. and Russian departments, agencies, ministries, and scientific institutions. – Benefit from and complement other established bilateral activities between the two countries.

SECTION 4: ACHIEVING GREENHOUSE GAS EMISSION REDUCTIONS – CHALLENGES AND COSTS

4.1 Assessing the Costs of CO_2 Capture and Sequestration

Although there is some consensus in the literature on the approximate cost of currently available CO_2 capture and storage (CCS) technologies, published cost estimates still vary widely (by as much as a factor of two). Cost estimates for many advanced technologies currently under study or development offer an even broader range of values. In some studies, CO_2 abatement costs are reported not for a specific technology, but on a sector-wide or nationwide basis (e.g., for the electric power industry, or the U.S. economy as represented by the GDP).

In this section of the report, we discuss some of the factors that underlie these differences and cloud a simple answer to what many believe is the simple question: How much does it cost to capture and sequester CO_2 emissions from power plants?

4.1.1 Defining the System Boundary

The first requirement of any economic assessment is to clearly define the "system" for which CO_2 emissions and cost are being characterized. The most common assumption in economic studies of carbon sequestration is a single power plant that captures CO_2 and transports it to an off-site storage area such as a geologic formation. The CO_2 emissions not captured are released from the power plant stack along with other emissions.

Other system boundaries that are used in reporting CO_2 abatement costs for a single facility include the power plant only, without CO_2 transport and storage. Alternatively, costs sometimes include CO_2 emissions over the complete fuel cycle that encompasses the mining, cleaning, and transportation of coal used for power generation, as well as any emissions from by-product use or disposal. Emissions of other GHGs are included in some analyses.

Still larger systems might include all power plants in a utility company's system, all plants in a regional or national grid, or a national economy where power plant emissions are but one element of the overall energy system being modeled. In each of these cases it is possible to derive a mitigation cost for CO_2 , but the results are not directly comparable because they reflect different system boundaries and considerations.

4.1.2 Defining the Technology of Interest

Costs will vary with the choice of CCS technology and the choice of the power system that generates CO_2 in the first place. In studies of a single plant or technology, such definitions are usually clear. But where larger systems are being analyzed (as in regional or national studies), some of these choices may be unclear. The context for reported cost results is then unclear as well.

4.1.3 Defining the Technology Time Frame

Another factor that is often unclear in economic evaluations is the nature or basis of the assumed time frame for technology costs, particularly for "advanced" technologies that are not yet commercial. Such cost estimates frequently reflect assumptions about the "n^{th} plant" to be built sometime in the future when the technology is mature. Such estimates reflect the expected benefits of technological learning. The choice of time frame and assumed rate of cost improvements can make a big difference in CCS cost estimates.

4.1.4 Different Measures of Cost

Several different measures of cost are used to characterize CCS systems. Because many of these have the same units (e.g., \$/ton CO_2), there is great potential for misuse or misunderstanding.

One of the most widely used measures in studies of individual technologies is the "cost of CO_2 avoided." This is defined as:

$$\text{Cost of } CO_2 \text{ Avoided} = \frac{(COE)_{capture} - (COE)_{ref}}{(CO_2/kWh)_{ref} - (CO_2/kWh)_{capture}}$$

This value reflects the average cost (\$/ton CO_2) of reducing atmospheric CO_2 emissions by one unit of mass (nominally 1 ton), while still providing one unit of electricity to consumers (nominally 1 kWh). Thus, the choice of both the capture plant and the reference plant without CO_2 capture and storage plays a key role in determining the CO_2 avoidance cost. Usually, the reference plant is assumed to be a single unit the same type and size as the plant with CO_2 capture. If there are significant economies of scale in power plant construction costs, differences in power plant size also can affect the cost of CO_2 avoided.

A measure having the same units as avoided cost can be defined as the difference in net present value of projects with and without CCS, divided by the difference in their CO_2 mass emissions. Unless the two projects produce the same net power output, the resulting cost per ton is not the cost of CO_2 avoided; rather, we call it the "cost of CO_2 abated." Numerically, this value can be quite different from the cost of CO_2 avoided for the same two facilities.

The marginal or average cost of CO_2 abatement for a *collection of plants* (as in a utility system, regional grid, or national analysis) also can be expressed in terms of \$ per ton of CO_2 reduced. These results depend on a host of assumptions about the technologies and fuels included in the analysis (including fuel price projections). Results from such studies have a different meaning than those from studies of a single plant or technology.

Arguably, the impact of CO_2 abatement on the COE is most relevant for economic, technical and policy analyses. For a single plant or technology, the COE can be calculated as:

$$COE = [(TCR)(FCF) + (FOM)]/[(CF)(8760)(kW)] + VOM + (HR)(FC)$$

TCR = total capital requirement ($),* *FC = fuel cost ($/kJ),
FCF = fixed charge factor (fraction/yr), *CF = capacity factor (fraction),*
FOM = fixed operating costs ($/yr), *8760 = hrs/yr*
VOM = variable operating costs ($/kWh), *kW = net plant power (kW).*

Thus, many factors affect the COE (and hence, the cost of CO_2 avoided as well). Cost studies can differ widely in their assumptions about these factors. For example, assumptions about the plant capacity factor have a large impact on the calculated COE.

For a variety of reasons, cost studies often do not report all of the key assumptions that affect the cost of CO_2 control. For example, the total capital requirement includes the cost of purchasing and installing all plant equipment, plus a number of "indirect" costs that typically are estimated as percentages of total plant cost.[10] Assumptions about such factors (such as contingency costs) can have a pronounced effect on cost results. Further, some CO_2 cost studies exclude certain items (like interest during construction and other "owner's costs") when reporting total capital cost and COE. Thus, the use of terms like "total plant cost" doesn't always mean what it seems. Unless such assumptions are transparent, results can easily be misunderstood.

Finally, for studies involving multiple plants (often using different fuels and technologies), aggregate cost results, such as a change in the average COE, reflect a much larger set of assumptions than cost estimates for a single plant. Macroeconomic studies of a national economy, in which energy costs are but one element of a complex modeling framework, offer cost measures such as the change in GDP from the imposition of a carbon constraint. These reflect myriad assumptions about the structure of the economy and the values of specific model parameters. Such results are far more difficult to understand fully, in terms of the influence of particular assumptions on reported results.

4.2 <u>Economics of CO_2 Capture and Sequestration</u>

4.2.1 Impacts of GHG Reduction Requirements on Existing Coal-Based Plants

Future GHG emission constraints would affect the price and availability of electricity — two factors that could have a profound impact on the U.S. economy. Because coal is abundant domestically and its price is low and stable relative to other fossil fuels, the predominance of coal-based power plants has helped keep U.S. electricity affordable, reliable, and secure.

If stringent CO_2 reduction requirements are imposed, the cost of electricity and the balance in the fuel mix could change dramatically. CO_2 removal technologies would be unprecedented in their cost and energy consumption, compared to the emission controls for SO_2, NOx, and particulates adopted over the last 30 years. In the absence of commercially available CO_2 capture and sequestration technologies, near-term (<10-12 years) CO_2 emission reduction requirements would likely force many coal-fired plants to be retired prematurely. This would likely lead to a further surge in the construction of new NGCC plants. Such a shift would place tremendous to tie electricity prices ever more tightly to the price of natural gas–a fuel with a much more volatile price history than coal. While the historic price differential of gas to coal is about 2:1, recent trends and availability projections may make that gap even greater in the future. Under this scenario, higher natural gas price prices would result in great impacts on the cost of electricity, and on the economy in general.

4.2.2 Technical Challenges of CO_2 Removal and Sequestration at Coal-Based Plants

The key challenges for CO_2 removal are energy use and cost. The key challenge of long-term storage or sequestration is the fate of the CO_2 (how well it will stay sequestered). The leading candidates for demonstrations to gain experience with CO_2 removal at coal-based plants are solvent absorption/stripping processes that are commercially used in other industries. Only modest work has been completed to date on adapting these technologies for use in existing power plants. Serious technical and economic challenges remain both within the CO_2 removal step itself and in pre-process cleanup of the gas stream to remove trace constituents that would contaminate the solvents.

In PC plants with today's commercial technology, CO_2 would be removed from flue gas in an absorber vessel using a solvent such as MEA. The CO_2 would next be stripped from the solvent via heat in a separate vessel, and the solvent returned to the absorber column. The heating requirements reduce the net power plant output. Because flue gas is at atmospheric pressure, and is composed primarily of nitrogen from the combustion air, the partial pressure of CO_2 (the key parameter determining the necessary solvent quantity, equipment size, and regeneration energy) is low. This results in large and costly CO_2 removal equipment. For example, the MEA process will increase the wholesale COE for a new, high-efficiency PC-SC plant by approximately 60% and consume about 29% of the plant's energy output.

IGCC plants offer the opportunity for CO_2 removal at a lower incremental cost and with a lower energy penalty because the removal step can be performed on high-pressure/high CO_2 concentration syngas prior to its combustion in the gas turbine. The partial pressure of CO_2 is higher if the gasifier is oxygen-blown (rather that air-blown), and the synthesis gas is "shifted" to convert CO to CO_2. A physical solvent absorption/stripping method, such as the Selexol process, appears most promising for bulk CO_2 removal. A DOE-EPRI study suggested that coal-based IGCC systems might be the most economical option for new generating capacity *if* CO_2 removal is required and *if* goals for reducing IGCC cost and improving availability are met.

In 2000, DOE and EPRI conducted a comprehensive engineering economics study (subsequently updated in 2002[6]) to look at new plant economics and design for CO_2 removal. This study developed engineering and cost estimates to:
(1) predict the cost and performance impacts of MEA absorption/stripping applied to conventionally designed PC plants and NGCC plants, and those of the Selexol process applied to IGCC plants; and
(2) identify which coal plant options would most effectively compete with NGCC plants if 90% CO_2 removal were required.

The plant designs evaluated in the study were intended to represent the next generation of commercially available power systems: PC plants with SC and USC steam conditions, IGCC plants with H-Class gas turbines, and NGCC plants with F-Class and H-Class gas turbines.

Key results from this study include (values converted to tons of CO_2):

- The levelized cost per metric ton of CO_2 removed was \$17.73 for IGCC units, \$38.55 for USC PC units, and \$54.91 for NGCC units with H-Class turbines.
- If 90% CO_2 removal were required for new fossil fuel power plants, and the constant dollar cost of coal remains at approximately its current rate of \$1.26/MBtu, then NGCC plants appear to offer the lowest levelized COE up to a natural gas price of \$3.64/MBtu. If the constant dollar cost of natural gas were higher, then IGCC plants would have the lowest COE.
- For 90% CO_2 removal, IGCC plants appear to have a COE up to \$18/MWh (~ 25%) lower than PC plants.

4.2.4 Strategies for an Economically Feasible Transition to a CO_2-Restricted Environment

There are approximately 305 GW of coal-fired generating capacity in the U.S. Eighty percent of this existing capacity will be at least 30 years old by 2007. The capital costs and efficiency penalties for retrofitting this fleet with current CO_2 removal technology would be considerably higher than the values discussed above for new plants. However, the existing plants are likely to continue operation for decades, and thus will represent the greatest source of coal-related CO_2 emissions for the foreseeable future. Therefore, the development of cost-effective CO_2 removal technology for retrofit application to existing plants, while a great technical challenge, is a worthwhile research target.

Retrofits would be costly because of the usual retrofit considerations, such as space constraints and site access difficulties, and because of difficulties in installing the equipment required for

[6] *Evaluation of Innovative Fossil Fuel power plants with CO_2 Removal* US DOE and EPRI Report December 2000, EPRI report number 1000316. *Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal* US DOE and EPRI, Palo Alto CA, U.S. Department of Energy, Office of Fossil Energy Washington, D.C.

absorption/stripping amines or cause corrosion problems. The cost of retrofitting CO_2 removal systems based on current technology would be prohibitive for most coal-based power plants, and many might be replaced with NGCC, despite concerns about natural gas price volatility and fuel diversity.

A recent study by EPRI[7] provided costs to remove CO_2 and upgrade existing emission controls at existing plants. The cost is estimated to be much higher than for new plants. The capital cost for a variety of emission control schemes, including retrofitting CO_2 scrubbers, or retrofitting O_2 combustion and recycle, all exceeded $1,000/kW, doubling or tripling the COE.

Given the significant cost and performance issues for retrofitting existing CO_2 control technologies on existing coal-based plants, which provide the basis for low-cost electricity in the U.S., it may be appropriate to allocate R&D dollars toward the development of more cost-effective removal options for both new and existing plants. Such an effort should include not only a means to better adapt existing solvent-based techniques to coal-based power plants, but also to explore promising novel technologies now in the laboratory or conceptual stage of development.

Because CO_2 removal methods appear much more energy-efficient and cost-effective when applied to IGCC plants, R&D to improve the cost and reliability of the power block portions of IGCC plants will be a crucial complement to work on CO_2 removal systems. Because the nature and timing of CO_2 reduction requirements are uncertain, the development of "phased" IGCC plant designs, in which plants are built to accommodate later installation of CO_2 removal technology, could help avoid retrofit burdens.

IGCC may only become broadly competitive with PC and NGCC plants under a CO_2-restricted scenario. Therefore, vendors currently do not have an adequate economic incentive to invest R&D dollars in IGCC advancement. Similarly, power companies are not likely to pay the premium to install today's IGCC designs in the absence of clear regulatory direction on the CO_2 issue. Therefore, accelerating the development of low-cost, low-CO_2-emitting CCTs, such as IGCC, will require substantial cooperation and funding from both public and private sources.

4.3 The Need for Large-Scale Demonstrations

4.3.1 R&D Timeframe

As with any major new technology with enormous financial, environmental, and energy security ramifications, CO_2 sequestration technologies cannot be considered commercially ready until they are successfully proven at full-scale, under "real-world" conditions, for a period of time adequate to assure expectations of prolonged safety and reliability. Any demonstration needs to convince prospective public-sector and private-sector investors that the costs and risks are sufficiently understood and acceptable so as to enlist the commitment of manufacturers and service providers, financiers and insurers, state and local authorities, as well as the public.

[7] *Options for Removing Multiple Pollutants Including CO_2 at Existing Coal-Fired Power Plants*, EPRI, Palo Alto,

Given the diverse make-up of the coal-based generating fleet, the wide variation in the types and properties of regionally economical fuels for power production, and the tremendous range of terrestrial ecosystems and subsurface geological features found across the U.S., effective national deployment of carbon sequestration measures will require the development and commercialization of a ***portfolio*** of CO_2 capture and disposal technologies.

To begin to populate a commercial sequestration technology portfolio over the medium term (i.e., 8-15 years), development and/or refinement of the most defined promising options and pilot-scale demonstrations must begin immediately. Commercial success at full scale will require the effective integration of technologies for capturing CO_2 at power plants, safely transporting it to disposal sites, and assuring that placed CO_2 will remain sequestered from the atmosphere for centuries. Therefore, addressing integration issues in conjunction with the pilot-scale demonstrations will accelerate their resolution at full scale.

4.3.2 CO_2-Capture Technologies

Because a requirement for CO_2 emissions reductions much greater than those attainable through efficiency improvement could occur before any substantial turnover in the capital stock of U.S. power plants, capture technology RD&D should concentrate on systems suitable for retrofit to today's PC units and for incorporation in coal repowering projects. Successful development of such retrofit and repowering technology would not only satisfy domestic needs, but also position the U.S. to be a technology exporter because PC plants are the predominant type of generating unit throughout the world.

Another priority for CO_2-capture technology RD&D should be the development of systems for IGCC plants. As a major DOE-EPRI evaluation of potential capture technologies found, the incremental cost and energy penalty for CO_2 removal from IGCC syngas is much lower for PC flue gas. IGCC plants can also accommodate low-grade fuels and offer the potential for co-production of steam and clean transportation fuels, making them attractive for new coal capacity, assuming that goals for cost reduction and availability improvement can be met.

Because the costs and energy penalties for the most-developed CO_2-capture technologies (i.e., those that are commercial in other, albeit smaller, industrial applications) appear high, two parallel research paths are recommended for the near term (within the next 5-7 years):

- Refine, to the extent practical in a short period, the processes that are commercial in other industries and are adaptable to large coal-fired power plants. Then begin demonstration testing at "flexible" pilot-scale facilities. These pilot-scale facilities would accommodate equipment configurations to allow testing of multiple processes, including those that are not yet ready at the commencement of initial tests, thereby avoiding the expense and time delay of having to build a separate pilot plant for each candidate process. This approach will advance capabilities in technology assessment, help researchers gain experience in running pilot CO_2-capture tests, and produce CO_2 gas streams with trace constituents representative of "real-world" power plants, which is vital for sequestration demonstrations.

promise lower cost, the production of easier-to-place solid products, and greater public acceptance. Emphasizing more "fundamental" research is important because breakthroughs in cost and energy use for commercially available chemical and physical processes are not expected.

4.3.3 PC Plants

The commercial technology most cited as potentially applicable to capturing CO_2 from the large volumes of flue gas produced by PC power plants is MEA absorption/ stripping. DOE and EPRI have estimated that the MEA process will increase the wholesale COE for a new, high-efficiency SC-PC plant by about 60% and consume about 29% of the plant's energy output. The cost and energy penalties for most existing PC plants, which have lower-efficiency subcritical steam conditions, will be considerably higher.

There are opportunities for improvement. Pilot-scale demonstrations of MEA scrubbing at power plants would allow researchers to experiment with designs that use less energy and, therefore, reduce the COE increase. Parametric testing could correlate MEA scrubbing performance as a function of fuel type, gas temperature, concentration of minor or trace flue gas constituents, such as SO_2, and other factors. Multiple pilot units will be required to span the full range of conditions present in the U.S. generating fleet.

Since the use of MEA-based systems will lead to significant reductions in efficiency for coal-based power plants, continuing to work solely with this technology will likely not provide the performance or economics needed for low-cost GHG emission reductions. Since these systems require significant amounts of energy, more fuel resources will be utilized in the long run in order to overcome the lost power output. Development of other processes that utilize a new generation of solid and liquid sorbents with low regeneration energy may provide the needed answers. One alternative is the use of high temperature CaO-$CaCO_3$ cycles that operate above the thermodynamic power cycle and potentially do not reduce efficiency.

Pilot-scale testing also provides insight into the scalability of equipment to full scale. By leveraging the "best-of-breed" process conditions and equipment designs from a series of pilot-scale demos, large-scale demonstrations can be conducted at lower risk of material and other "nuisance" failures, thereby helping to assure cost-effective development of information suitable for commercialization decisions.

4.3.4 IGCC Plants

The commercial technologies that appear most promising for removing CO_2 from IGCC syngas are derived from acid-gas cleanup methods used in the oil and gas industry, such as the Selexol process. Selexol, in particular, also has been used in conventional IGCC units (i.e., those without CO_2 capture) for removing H_2S and COS from syngas to prevent corrosion in downstream heat exchangers and the combustion turbine.

CO_2 emissions, they require that the gasifier be operated in a "shift" mode to produce syngas with more H_2 and CO_2 and less CO. Selexol and other candidate processes for CO_2 capture from IGCC power systems exact a smaller loss in the plant's energy output, relative to MEA processing of PC plant flue gas, because the volume of syngas to be treated is approximately 1/200th of that involved in treating post-combustion flue gas

According to a DOE-EPRI study, the total incremental cost of CO_2 removal from an IGCC plant could be only about 40% of that from a PC plant. The overall relative competitiveness of IGCC plants and PC plants with CO_2 removal is unclear, and depends on future relative capital costs, fuel costs, availability rates, and non-fuel O&M costs. Under one scenario examined by DOE and EPRI, an IGCC plant's COE could be as much 25% lower than that of a PC plant. Given such projections, developing and commercializing CO_2-capture technologies for IGCC plants would be vital to improving the economics of clean coal power systems.

As with PC plants, multiple IGCC demonstrations would be necessary given the substantial differences in the major types of gasifier designs and in the properties of regionally economical IGCC fuels.

4.3.5 Novel CO_2-Capture Technologies

Current candidate technologies for CO_2 capture from PC and IGCC units will remain relatively energy intensive and expensive. Over the near- to mid-term, it will be crucial to accelerate development and pilot-scale testing of novel CO_2 removal processes. Today, numerous novel processes have shown promise on the basis of conceptual evaluations and/or laboratory tests, but need refinement and subsequent testing at bench and pilot scale to assess their true potential and scalability. Such processes involve myriad physical, chemical, and biological principles. Examples include membrane separation, biomimetic reproduction of the enzyme used by mollusks to repair damaged shells (which then is used as gas scrubbing medium), chemical looping, mineralization, microbe/genetic engineering, oxyfuel combustion, and more.

4.3.6 CO_2-Sequestration Technologies

Because carbon sequestration requires the safe storage of CO_2 or other carbonaceous compounds and associated trace substances for indefinite periods, determining the capacity, effectiveness, and health and environmental impacts of CO_2 disposal options may require demonstrations lasting a decade or more (to assure confidence in the environmental integrity of storage sites and methods). It is highly desirable to begin such demonstration projects as soon as possible using CO_2 gas streams as "realistic" as possible in terms of the trace constituents produced by CO_2-capture process applied to coal-fired power plants.

Public acceptance of carbon sequestration demonstrations, let alone full-scale applications, can be expected to vary depending on the location(s) of storage sites and the types of storage technology used. In general, public acceptance is likely to be highest for terrestrial solutions (e.g., tree planting) and for geologic solutions involving pre-existing formations—such as depleted oil and gas wells

In the intermediate and long-term, geologic solutions offer significant potential for CO_2 storage capacity. Terrestrial options, such as forests, require long-range planning and may take 25-50 years to reach full capacity but they may have collateral benefit (habitat creation, enhanced agricultural practices, ecological restoration, etc.) which mean that they should be implemented early. Currently, the injection of CO_2 into geological formations is practiced at numerous sites worldwide for EOR and EGR.

Small-scale demonstrations of geologic CO_2 disposal options could establish a benchmark for trace leakage and help gauge risks for rapid release. Over the medium term, larger-scale demonstrations of geologic solutions as well as pilot-scale demonstrations of the potentially more complex oceanic disposal will be necessary to ensure sufficient CO_2 disposal capacity to support significant CO_2 emissions reductions via sequestration.

R&D should also evaluate novel sequestration options that produce stable, solid products, ideally with a market value to help offset processing costs. DOE's Albany Research Center is already experimenting with CO_2-rich "bricks."

4.3.6 The Value of Integrated Demonstrations

Integrated demonstrations, in which power plant CO_2 capture, transport, and disposal components are combined, are critical to improving the industry's understanding of the real-world feasibility of carbon sequestration in terms of costs, health and environmental impacts, risks, legal and liability issues, and public acceptability.

Early insights in this regard could prove highly valuable in terms of informing today's decisions on technology selection and siting for new power plants that would make them more or less amenable to subsequent CO_2-capture technology retrofits.

Large-scale integrated demonstrations also give power plant owners, technology developers, financiers and insurers, and policymakers greater confidence that successful demonstration results portend collective movement of all the necessary market actors toward true, self-sustaining commercialization of carbon sequestration technology.

4.3.7 Challenges

Key challenges include securing funding for multiple large-scale demonstrations and, especially for CO_2 disposal, obtaining permits from local governments. Addressing the funding issue will require strong public-private partnerships. In some cases, the power industry may work closely with other industrial sectors, such as where valuable products could be co-produced and sold in the process of disposing of CO_2 (e.g., EOR, EGR, or CBM production). Local permitting agency concerns may be addressed through education programs designed to accurately present potential risks and benefits of carbon sequestration. Leveraging small-scale demonstrations to gather data prior to large-scale storage projects will help researchers quantify these risks.

The recently announced Presidential FutureGen Sequestration and Hydrogen Research Initiative could well serve as a major platform for developing CO_2 sequestration in conjunction with coal gasification. This initiative will speed the development of hydrogen production based on coal and of CO_2 sequestration technologies applicable to coal gasification. This program also matches the recommendation of the National Research Council's Review of Vision 21 in which they recommended..."The Vision 21 program should continue to sharpen its focus. It should focus on the development of cost-competitive, coal-fueled systems for electricity production on a large scale (200-500 MW) using gasification-based technologies that produce sequestration - ready CO_2 and near-zero emissions of conventional pollutants." This program also should meet specific gasification development and sequestration goals developed in joint industry-government roadmapping documents such as those developed in conjunction with DOE/ EPRI and CURC (refer to http://www.coal.org/rdmap.htm).

This unique facility is envisioned to provide R&D capability to allow testing of novel equipment under realistic conditions and may carry a significant share of U.S. R&D activities. It will still be necessary to have multiple demonstrations or combinations of pilot and demonstration projects to cover differing gasification designs, or designs not based on gasification technology, with differing coals, and differing regional types of sequestration.

4.4 Future Programs for Voluntary Actions

4.4.1 Summary

The federal government has established or is establishing several programs to address the technical, environmental and societal challenges to widespread adoption of GHG management technologies by private industry. Three of these programs are highlighted in this report: Regional Partnerships for Carbon Sequestration; the Climate VISION Program, and the Carbon Sequestration Leadership Forum.

Under the ***Regional Partnerships*** program, DOE has called for proposals to identify the opportunities and impediments to carbon sequestration, recognizing the distinct differences likely for different geographic regions. These projects, conducted over the next two years, are intended to lead to larger scale field tests of promising sequestration options on a regional basis.

In February, 2002, the President announced the goal of reducing GHG intensity by 18% over the next decade, and called on private industry to work in partnership with the government to meet this goal. In February, 2003, DOE responded by announcing agreements with the major industrial sectors[8] to participate in its ***Climate VISION*** program, creating voluntary public-private partnerships administered by the DOE, to pursue cost-effective initiatives that will reduce the projected growth in America's GHG emissions.

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[8] Oil and Gas Production, Transportation and Refining, Electricity Generation, Coal Production and Mining, The Portland Cement Association (PCA) , The American Iron and Steel Institute (AISI), The Semiconductor Industry Association (SIA), Magnesium Coalition and the International Magnesium Association, The American Chemistry Council (ACC), The Aluminum Association, The Association of American Railroads (AAR), The Alliance of

On February 27, 2003, the Departments of State and Energy announced the formation of the ***Carbon Sequestration Leadership Forum***, a ministerial-level international organizational focus on development of carbon capture and storage technologies as a means to stabilizing atmospheric GHG concentrations. The partnership will promote coordinated research and development with international partners and private industry, including data gathering, information exchange, and collaborative projects.

4.4.2 Regional Partnerships for Carbon Sequestration

Among the many elements of its GHG management program, the DOE has issued a solicitation[9] to establish "regional partnerships" to facilitate the development and use of technology for the capture, transport, and storage of CO_2 from anthropogenic sources throughout the U.S. This concept recognizes that patterns of fossil fuel use, and the nature and location of potential sequestration sinks differ widely throughout the U.S. As a result, distinctly different regional approaches may be required if the country as a whole is going to address the issue of CO_2 in a cost effective manner. In addition to the technological factors affecting the regional sequestration option, social, legal and regulatory issues (including permitting requirements and public acceptance) need to be addressed on a regional and local basis.

DOE envisions these issues being addressed by a number of regional partnerships, which would include fuel producers, energy producers, consumers, industrial entities, the academic and research community (academia and environmental advocacy organizations), and state agencies.

The regions will be defined by the participants in a partnership based on commonality of technical, economic, and political interests. The specific objectives set out by DOE for Phase I of the regional partnership program include:

- Defining the geographical boundary of the region;
- Characterizing the region for its sources, potential sinks, and key infrastructure requirements, such as CO_2 transportation mechanisms;
- Developing action plans which identify and address critical issues for wide-scale use of the most attractive regional sequestration approaches;
- Defining mechanisms to ensure public awareness and acceptance of carbon sequestration; and
- Analyzing the results of the foregoing steps to identify the most attractive options in a regional context on the basis of economic, environmental, and social criteria to select prime candidates for future large-scale demonstrations.

Under Phase II of the program, participants would conduct small-scale field tests to demonstrate the validity of the sequestration options identified in the assessment and analysis phase of this program.

[9] DE-PS26-03NT41713 "Regional Carbon Sequestration Partnerships – Phase I". The due date for proposals was

million to each for initial Phase I planning. As much as $7 million could be provided to partnerships for the field verification tests and further regulatory and infrastructure assessment expected to be conducted in Phase II.

4.4.3 Industrial Commitments to Voluntary Emissions Reductions Under the Climate VISION Program

On February 14, 2002, President Bush committed to reducing America's GHG intensity (the ratio of emissions to economic output) by 18% in the next decade. On February 12, 2003, the DOE announced the Administration's Climate VISION (Voluntary Innovative Sector Initiatives: Opportunities Now) Program, a voluntary, public-private partnership to pursue cost-effective initiatives that will reduce the projected growth in America's GHG gas emissions. Climate VISION will be administered through the DOE's policy and international program. The industry sectors which announced their participation and their stated goals are described below.

Oil and Gas Production, Transportation and Refining
The API proposed to increase the energy efficiency of members' U.S. refinery operations by 10% from 2002 to 2012 through reduced gas flaring and other energy efficiency improvements, expanded combined heat and power facilities, increased by-product utilization, and reduced CO_2 venting. API members will develop GHG management plans to identify and pursue opportunities to further reduce emissions.

Electricity Generation
EEI and six other power sector groups[10] formed the Electric Power Industry Climate Initiative (EPICI) to reduce the sector's carbon intensity. The EPICI will pledge to reduce the power sector's carbon impact in this decade by the equivalent of 3-5% through increased natural gas and CCT, increased nuclear generation, offsets, and expanded investment in wind and biomass projects.

Coal Production and Mining
The National Mining Association (NMA) committed to achieving a 10% increase in the efficiency of those systems that can be further optimized with processes and techniques developed by DOE and made available through the pending NMA-DOE Allied Partnership. The commitment includes steps to recover additional CMM, expansion of land reclamation, carbon sequestration efforts, and coal and mining research.

The Portland Cement Association (PCA)
PCA has committed to reduce CO_2 emissions by 10% per ton of cement from a 1990 baseline by 2020 through enhancements to the production process, the product itself, and how the product is applied.

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[10] National Rural Electric Cooperative Association, the Nuclear Energy Institute, the American Public Power Association, the Large Public Power Council, the Electric Power Supply Association, and the Tennessee Valley Authority.

Thirty-three member firms, representing nearly three-quarters of the nation's steel-producing capacity, have committed to achieving a 10% increase in sector-wide average energy efficiency by 2012 from 1998 levels.

The Semiconductor Industry Association (SIA)
SIA committed to reduce a suite of the most potent GHG emissions (HFC, PFC and SF6 "perfluorocompounds") by 10% from 1995 levels by the end of 2010. EPA estimates that this will reduce emissions by over 13.5 MMTCE in the year 2010, or the equivalent of eliminating GHG emissions from 9.6 million cars.

Magnesium Coalition and the International Magnesium Association
Magnesium Coalition and the International Magnesium Association companies have committed to eliminate sulfur hexafluoride (SF6) emissions from their magnesium operations by 2010, which will have a climate benefit equivalent to eliminating 1.4 MMTCE in GHG emissions.

The American Chemistry Council (ACC)
The ACC, whose members operate 90% of the chemical industry production in the U.S., has agreed to an overall GHG intensity reduction target of 18% by 2012 from 1990 levels through increased production efficiencies, promoting coal gasification technology, increasing bio-based processes, and by developing products which increase energy efficiency in other sectors

The Aluminum Association
The Aluminum Association is committed to reducing sector-wide GHG emissions. Through one of the first voluntary partnerships with EPA in 1995, the Voluntary Aluminum Industry Partnership (VAIP) reduced perfluorocarbon (PFC) emissions in 2000 by over 45% compared to 1990 levels.

The Association of American Railroads (AAR)
The AAR has committed to reducing the transportation-related GHG intensity of their Class 1 railroads by 18% in the next decade.

The Alliance of Automobile Manufacturers (AAM)
AAM has agreed to reduce GHG emissions from its members' manufacturing facilities by at least 10% by 2012, based on U.S. vehicle production from a 2002 baseline by installing energy efficient lighting, converting facilities' coal and oil power sources to cleaner natural gas, and upgrading ventilation systems.

The American Forest and Paper Association (AF&PA)
AF&PA members expect to reduce their GHG intensity by 12% by 2012 relative to emissions levels in 2000 through the Sustainable Forestry Initiative program, recycling, avoiding landfill methane emissions, and increasing carbon storage.

On February 27, 2003, the Departments of State and Energy announced the formation of the ***Carbon Sequestration Leadership Forum***, a ministerial-level international organization focusing on enhancing international opportunities related to GHG management. The partnership will promote coordinated research and development with international partners and private industry, including data gathering, information exchange, and collaborative projects.

An inaugural meeting, scheduled for June, 2003, will involve presentations by government, the private sector, and non-governmental organizations on the status of sequestration research and the technical, economic, and public policy challenges that must be addressed. A Ministerial Roundtable will be held to discuss the Forum and each country's goals in participating.

The Carbon Sequestration Leadership Forum does not change any of the existing bilateral agreements that the U.S. has with many countries. Instead, it is intended to focus the efforts of the international community specifically on carbon sequestration as one option in an overall GHG mitigation strategy.

In that regard, it is worth noting that, at its meeting on February 19-21, 2003, the IPCC[11] gave formal approval to the writing of a Special Report on CO_2 Capture and Storage as a climate change mitigation option. The report will be written under the auspices of Working Group III (WGIII) on Mitigation. The Energy Research Centre of the Netherlands (ECN) operates the Technical Support Unit for WGIII. The Special Report will take two years to complete, with delivery planned for the first half of 2005. A workshop to prepare a scoping paper for this report met November 18-21, 2002, in Regina, Canada (workshop proceedings available at http://www.climatepolicy.info/ipcc). According to that scoping paper, reasons to proceed with this report include:

- CO_2 capture and storage is an emerging technology option with a very high mitigation potential. It has been suggested that about half the world cumulative emissions to 2050 may be stored at costs comparable to other mitigation options.
- The keen interest in this subject is demonstrated by plans considered by several leading industrial countries to invest in this emerging technology in the coming years.
- There is a growing interest in the scientific and technical community in the subject of CO_2 capture and storage, demonstrated by the growing availability of the literature.
- Policymakers have a growing need for a reliable synthesis of the available scientific literature in order to facilitate the decision making process on the plans for CO_2 capture and storage as a climate change mitigation option.

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[11] The IPCC has been established by WMO and UNEP to assess scientific, technical and socio- economic

4.5.1 Incentives for New and Existing Facilities

Background

It is likely that existing coal-fired plants will continue to provide the bulk of our nation's electricity for decades to come, unless political decisions are made which force their retirement for economic reasons. Ultimately, economic and technical factors will make it necessary to build new power plants to replace retiring capacity and to meet load growth. As indicated in this report, significant reductions in CO_2 emissions can be achieved in the near term by increasing the efficiency of the existing generating fleet. Moreover, replacement of the existing units with new, more advanced CCTs can further increase fleet efficiency, and reduce CO_2 emissions. Finally, new plants can be designed to facilitate CO_2 capture and sequestration, if this becomes necessary, and technologically and economically feasible. Therefore, three principal elements of a strategy to reduce CO_2 emissions, while continuing to utilize our domestic coal resources are to increase efficiency on the existing generating fleet, replace existing capacity or add new capacity with more highly efficient advanced technologies, and prepare for possibility that carbon capture and sequestration may be necessary in the future.

An analysis of the previously reported actions under Section 1605(b) of the Energy Policy Act demonstrates that private companies are willing to take voluntary actions to reduce GHG emissions if technological and financial risks and rewards are acceptable. However, the goal of advancing new technology can be accelerated if incentives are available to offset the incremental risk taken on in early full-scale demonstrations and deployment of the most advanced technologies. These incentives can take the form of financial instruments intended to reduce the financial risk engendered by the technical uncertainty inherent in the demonstration or early use of new technology.

Two important components of federal policy in this regard are cost-sharing by the federal government in the first-of-a-kind demonstration of new technology, and tax incentives to encourage replicate deployment of demonstrated technologies. The latter is particularly important for encouraging investment in capital intensive technologies such as central-station coal-fired power plants. The argument is that some number of these new technologies needs to be built to move along the technology along a "learning curve" that reduces the technical risk and cost to the point that plants can attract conventional commercial financing.

This concept is embodied in the National Environmental and Energy Technology (NEET) legislation which has been introduced in both the House and the Senate.

Under NEET, tax incentives are provided for the installation of CCT that increases thermal efficiency and reduces emissions at coal-fired power plants. The bill includes provisions for existing and new plants. For existing facilities, the bill provides a production tax credit of \$0.0034/kWh for retrofitting or repowering of units to meet the energy efficiency and emission requirements qualifying it as CCT as defined in the bill.

For new units, NEET provides a 10% investment tax credit, and production tax credits of varying amounts, depending on the year in which the unit goes into operation and the efficiency (heat incentive increases as the efficiency of the unit increases.

4.5.2 Addressing regulatory issues

In some instances, environmental regulations can have the effect of impeding actions that would otherwise result in the reduction or sequestration of greenhouse gases. Two examples are cited here: reclamation requirements affecting carbon sequestration on mined lands; and interpretation of New Source Review regulations affecting the ability of power plants to make efficiency improvements.

1. Statutory and regulatory impediments to terrestrial sequestration at mining sites.
Opportunities exist for more CO_2 to be sequestered at surface coal mining reclamation sites by changing the laws, interpretations of laws, and local practices of mine reclamation to allow for more effective approaches to reforestation. Practices and laws governing post-mining land use, approximate original contour requirements, topsoil requirements, and revegetation requirements need to be addressed in order to promote increased forestation.

Post Mining Land Use. The Surface Mining Control and Reclamation Act (SMCRA) established that all areas disturbed during mining be restored in a timely manner to: (1) conditions that are capable of supporting the uses which they were capable of supporting before any mining; or (2) higher and better uses under certain criteria and procedures.

If land was not forested before mining, some jurisdictions have ruled that reforestation is not a higher and better use of the land. In particular, this is the case in the Midwest where pre-mine lands are designated as prime farmland. With the significant potential for CO_2 sequestration on mining lands through reforestation, State and Federal regulatory agencies should allow reforestation as a higher beneficial post-mining land use. This would require no change in regulation, just a change in classification.

Approximate Original Contour Requirements. Mining laws require that the land surface be returned to the approximate original contour (AOC) that existed prior to mining or an approved postmining topography (PMT) for thin overburden mines. The action of heavy equipment required to transport, backfill, and grade the material needed to create a narrowly defined AOC/PMT results in a highly compacted soil surface.

Highly compacted soils decrease tree survivability and do not allow for rapid and large tree growth. Reclamation regulations or enforcement practices should be changed to allow more flexibility in this area. This would reduce the intensity of grading, thus enabling an environment for proper tree growth and survivability, as well as enhancing CO_2 sequestration.

Topsoil Requirements. Topsoil removal, segregation, storage, and replacement are required in many jurisdictions. Some jurisdictions also require that topsoil be replaced at a uniform thickness.

In many areas of the country, larger and faster tree growth can be demonstrated by using mixed reclaimed surfaces, even though varying depths are found in the premining environment. Using thicker topsoil in valleys and thinner on peaks would help foster a more diverse vegetation cover. Flexibility in topsoil requirements would help to increase reforestation and the re-establishment of shrubs, also enhancing CO_2 sequestration.

Revegetation Requirements. SMCRA requires that mine permit holders establish a diverse, effective, and permanent vegetative cover of species native to the area to support the planned post-mining uses of the land. While this provision allows for non-native species of plants to be used, local regulation has not always allowed for this to happen. In order to maximize CO_2 uptake, non-native vegetation may need to be allowed.

2. ***New Source Review.***
A wide range of technologies are available for improving efficiency at coal-fired power plants. These include improvements in materials, upgrades of boiler pressure parts, burner improvements, and new designs for steam turbine blades. Such efficiency increases, as previously noted, would result in fewer GHG emissions per unit of fuel burned. As the Council noted in its May, 2001, report, "Increasing Electricity Availability from Coal-Fired Generation in the Near Term," the change in enforcement procedures by EPA (reinterpreting as violations of the Clean Air Act what had previously been considered routine maintenance at power plants) has had a direct and chilling effect on all maintenance and efficiency improvements at existing power plants.

At issue is whether or not these changes would in fact result in increased emissions of various pollutants, and if the utilities in question should have submitted permit applications prior to doing the maintenance or making the efficiency upgrades. EPA contends that certain methods of calculating future emissions could show increases, which would require that emission control systems would need to be retrofitted, at great cost and with significant project delay, negating any achievable increases in efficiency.

Over the past several years, EPA has continued to pursue the legal action, while at the same time proposing potential "fixes" to the new source review definitions, calculation methods, and enforcement. With some of the companies "settling" their cases, other cases being handled in venues in various states, and EPA continuing to re-propose various regulatory "fixes," it is likely that various outcomes will occur, making it even more difficult for utilities to determine how to proceed on what would otherwise have been the "right" thing to do, with improvements in efficiency being stalled. As the Council noted previously, legislative action to make the appropriate corrections on a nationwide basis may be the best option to promote efficiency improvements that would led to lower emissions of GHGs from coal-fired power plants.

4.5.3 Transition Issues for Coal Generation

Implementing the technologies described in the previous sections of this report will require transitions both in the technology itself and in the policies and regulations that will govern the generation business of the future. The need for orderly transitions is necessary due to the desire to minimize technical and financial risk on the parts of the generating companies and the

Coal-fired power plants, once thought to be facing a rapid demise, now are broadly perceived as one element of a strategy to use indigenous resources for the future energy security of the country. Transitioning to this future will require concerted efforts in four interdependent areas:

- Developing public/private partnerships to fund technology development and demonstrations;
- Creating tax and other incentives to encourage investment in technology development and implementation;
- Designing a technology rollout strategy to implement new technologies while reducing the associated technology and financial risks; and
- Managing an institutional transition to address public policy, regulatory, and environmental/ ecological issues.

4.5.4 Funding Technology Development Through Public/Private Partnerships

To assure the future of coal-based generation, it will be necessary to increase efficiency and reduce emissions while decreasing capital and operating costs. CCTs, such as USC and IGCC power plants, have the potential for conversion efficiencies of >50% (LHV). Deployment of these technologies will depend on lower fuel costs to help offset the higher capital cost of these options. Current estimates suggest that these technology advances have the potential to make new clean coal generation competitive with equivalent NGCC plants on a cost of electricity basis in the 2010 to 2020 time frame. In certain niche areas or cases, IGCC may be able to take advantage of low-cost and opportunity fuels, and of its superior environmental performance, to compete in the next seven to 10 years.

Timely advances in coal technology cannot be achieved without a significant increase in RD&D funding that will permit commercial viability within the next 10 years. This is problematic in the current economic and regulatory environment because power plant operators are under extreme pressure to reduce costs and are unwilling to invest in new technologies. Investing now in an advanced power plant technology requires patience, because the investment will not earn a return until some time after successful commercialization.

All of these issues suggest that traditional forms of private-sector funding for new technologies may not be feasible in today's electricity generation business environment. Public-private consortia are emerging as a mechanism to provide the needed resources for technology development. They allow for front-loading the R&D processes, as well as the early stages of pilot and full-scale tests. DOE funding of research for the advanced coal program follows this precept, in that the DOE cost share is higher for high-risk technology development and lower for commercialization activities. This approach has been a success in prior programs, such as the CCT Program, and is working well to sustain interest in the current Vision 21 program. It is anticipated that it will be successful in the FutureGen program as well.

Although these programs encourage private sector participation in the technology development process, the current funding levels are not adequate to develop and commercialize the systems.

Additional R&D is necessary for the following specific technologies and high priority issues:

- High-pressure solid feed systems;
- Fuel cell development and testing;
- Slip stream testing of fuel cells;
- High-temperature metallic heat exchangers (for service at 1800°F);
- Gasifiers for high-ash, high-moisture coals;
- Enhanced trace element monitoring; and
- Char combustion and gasification.

4.5.4 Investment Incentives

Government action should not be limited to research funding. There is a clear role for government in supporting the deployment of CCT to improve fuel diversity and reduce emissions. Without a strong advanced technology development program, there will be dramatic reductions in the use of coal over the next 30 years and a huge increase in natural gas consumption for electricity generation. This prospect threatens the energy security and perhaps the economic well-being of the U.S. One answer is a national strategy that encourages the balanced use of all our energy resources -- coal, gas, nuclear, and renewable energy sources.

With respect to coal-based technologies, incentives are needed to address the issues associated with building new plants due to uncertainties about future emissions control requirements.

It is possible to define a tax and incentive package aimed at boosting the maximum generation efficiency of coal-based power plants to 50% or higher (LHV). Achieving these goals would produce significant environmental benefits.

Three types of incentive package have been proposed to encourage early commercialization of advanced coal technologies:

- An investment tax credit tied to the project owner's equity;
- A variable production tax credit tied to energy production and energy efficiency over the first 10 years of operation, with higher benefits to early implementation of high efficiency technologies; and
- A "risk pool" to cover repairs or modifications necessary to achieve the required performance during startup and the first three years of operation.

4.5.5 Technology Rollout Strategy

Investors and operators are reluctant to be the owners of "Serial No. 1." This suggests the need for a strategy of rolling out technologies in a series. The first units in a series would have modest improvements in performance, with minimal additional financial risk. In addition, the initial technology advances would be familiar to the operators, minimizing re-training. This suggests gas produced by a slagging gasifier might be a better choice for an organization with prior experience in some or all of the unit processes implied in a sophisticated hydrogen production operation.

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APPENDIX A
SELECTED TABLES & FIGURES

Project Title	Performer Type	Performer	Project Start Date	Project End Date	Total Estimated Cost	DOE Share
Ocean Carbon Sequestration	Gov't Agency	Department of Navy - Naval Sea Systems Command	07/07/1999	03/30/2003	$576,094	$576,094
Terrestrial Sequestration of CO_2	Gov't Agency	USDA - Forest Service - Southern Research Station	09/07/1999	09/29/2004	$75,000	$25,000
Carbon Capture and Water Emissions Treatment System (CCWESTRS) at Fossil-Fueled Electric Generators	Gov't Agency	Tennessee Valley Authority	09/17/2000	09/29/2003	$1,289,007	$729,007
Chemical Fixation of CO_2 in Coal Combustion Products and Recycling Through Algal Biosystems	Gov't Agency	Tennessee Valley Authority	09/17/2000	09/29/2002	$755,291	$604,233
Economic Evaluation of CO_2 Sequestration Technologies	Gov't Agency	Tennessee Valley Authority	09/17/2000	07/30/2002	$1,321,113	$1,056,890
CO_2 Capture by Absorption with Potassium Carbonate	State Univ.	University of Texas at Austin	03/31/2002	03/31/2005	$728,007	$461,849
Laboratory Investigations in Support of CO_2-Limestone Sequestration in the Ocean	State Univ.	University of Massachusetts	03/31/2002	03/31/2004	$267,840	$206,290
Calcium Carbonate Prod. by Coccolithophorid Algae in Long-Term CO_2 Sequestration	State Univ.	California State University San Marcos	04/30/2001	04/25/2004	$306,846	$212,371
Atomic Level Modeling of CO_2 Disposal as a Carbonate Mineral	State Univ.	Arizona State University	06/11/1998	07/30/2002	$369,225	$199,697
P-H Neutral Concrete for Attached Microalgae & Enhanced CO_2	State Univ.	Louisiana State University	07/14/1998	05/14/1999	$50,373	$50,373
Optimal Geological Environments for CO_2 Disposal in Saline Reservoirs	State Univ.	University of Texas at Austin, Bureau of Economic Geology	07/23/1998	07/14/2004	$404,434	$404,434
Reactive, Multi-phase Behavior of CO_2 in Saline Aquifers Beneath the Colorado Plateau	State Univ.	University of Utah - OSP	08/08/2000	08/12/2003	$428,049	$342,412
Separation of Hydrogen and CO_2 Using a Novel Membrane Reactor	State Univ.	North Carolina A&T State University	08/18/1999	08/30/2002	$199,963	$199,963
High Temperature CO_2 Semi-Permeable Dense Ceramic Membranes	State Univ.	University of Cincinnati	08/24/2000	08/30/2002	$57,195	$49,999
An Innovative Concept for CO_2-Based Tri-generation of Fuels, Chemicals, and Electricity Using Flue Gas in Vision 21 Plants	State Univ.	Pennsylvania State University - University Park	08/29/2000	11/29/2001	$50,000	$50,000
Oxygen-Enriched Coal Combustion with CO_2 Recycle and Recovery	State Univ.	University of Utah - OSP	08/30/2000	05/29/2002	$49,719	$49,719

Project Title	Performer Type	Performer	Project Start Date	Project End Date	Total Estimated Cost	DOE Share
Preliminary Characterization of CO_2 Separation and Storage Properties of Coal Gas Reservoirs	State Univ.	University of Arizona	09/11/2001	09/10/2002	$49,997	$49,997
Development of Superior Sorbents for Separation of CO_2 From Flue Gas at a Wide Temperature Range During Coal Combustion	State Univ.	University of Cincinnati	09/17/2001	09/16/2002	$57,650	$50,000
Enhancement of Terrestrial C Sinks Through Reclamation of Abandoned Mine Lands in the Appalachians	State Univ.	Stephen F. Austin State University	09/19/2000	09/18/2003	$839,504	$628,169
Understanding Olivine CO_2 Mineral Sequestration Reaction Mechanisms at the Atomic Level: Optimizing Reaction Process Design	State Univ.	Arizona State University	09/19/2001	09/18/2002	$77,113	$49,170
Enhancing the Atomic Level Understanding of CO_2 Mineral Sequestration Mechanisms via Advanced Computational Modeling	State Univ.	University of Arizona	09/19/2001	09/18/2004	$262,545	$195,717
Active Carbonation: A Novel Concept to Develop an Integrated CO_2 Sequestration Module for Vision 21 Plants	State Univ.	Pennsylvania State University - University Park	09/23/2001	09/22/2002	$55,000	$50,000
CO_2 Sequestration and Recycle by Photosynthesis	State Univ.	University of Akron	09/23/2001	09/22/2004	$266,620	$199,965
Novel Nanocomposite Membrane Structures for Hydrogen Separation	State Univ.	University of Texas at Austin	09/26/2001	09/25/2004	$200,000	$200,000
Maximizing Storage Rate and Capacity and Insuring the Environmental Integrity of CO_2	State Univ.	Texas Tech University	09/27/2000	09/30/2003	$2,618,393	$2,081,348
Enhanced Practical Photosynthetic CO_2 Mitigation	State Univ.	Ohio University	09/27/2000	09/30/2003	$1,369,495	$1,075,022
Unminable Coalbeds & Enhancing Methane Production Sequestering CO_2	State Univ.	Oklahoma State University	09/28/1998	03/14/2003	$876,175	$820,649
CO_2 Sequestering Using Microalgal Systems	State Univ.	University of North Dakota Energy and Environmental Research Center	09/30/1998	03/30/2003	$0	$0
Geologic Screening Criteria for Sequestration of CO_2 in Coal: Quantifying Potential of the Black Warrior Coalbed Methane Fairway, Alabama	State Agency	Geological Survey of Alabama	09/28/2000	10/04/2003	$1,398,068	$789,565
CO_2 Removal from Natural Gas	Small Business -	Carbozyme,Inc.	08/26/2001	05/25/2002	$100,000	$100,000

Project Title	Performer Type	Performer	Project Start Date	Project End Date	Total Estimated Cost	DOE Share
Obtaining EPA Permits for CO_2 Ocean Sequestration Experiment in Hawaii	Small Business	Pacific International Center for High Technology Research	05/31/2002	10/29/2002	$60,495	$60,495
A Zeolite Membrane for Separation of Hydrogen from Process Streams	Small Business	TDA Research, Inc.	06/14/1998	03/13/1999	$100,000	$100,000
A Novel CO_2 Separation System	Small Business	TDA Research, Inc.	07/09/1998	12/30/2003	$549,999	$549,999
Sequestration of CO_2 Using Coal Seams	Small Business	Northwest Fuel Development Inc.	07/14/1998	05/14/1999	$56,752	$56,752
Natural Analogs for Geologic Sequestration	Small Business	Advanced Resources International	07/29/2001	07/30/2004	$1,736,390	$1,123,390
Organization of 2003 National Carbon Sequestration Conference	Small Business	Exchange Monitor Publications, Inc.	07/31/2002	07/31/2002	$245,120	$100,000
Oil Reservoir Characterization and CO_2 Injection Monitoring in the Permian Basin with Cross-Well Electromagnetic Imaging	Small Business	ElectroMagnetic Instruments, Inc.	09/10/2000	08/30/2003	$1,150,630	$767,821
Geologic Sequestration of CO_2 in Deep, Unmineable Coalbeds: An Integrated Research and Commer	Small Business	Advanced Resources International	09/27/2000	03/31/2004	$5,543,246	$1,387,224
Recovery & Sequestration of CO_2 from Stationary Comb. Systems by Photosynthesis of Microalgae	Small Business	Physical Sciences, Inc.	09/28/2000	09/30/2003	$2,361,111	$1,682,028
Support for the International CO_2 Ocean Sequestration Field Experiment	Small Business	Pacific International Center for High Technology Research	09/28/2001	09/29/2002	$93,613	$44,613
Weyburn CO_2 Sequestration Project	Non-US	Natural Resources Canada-CANMET	05/31/2002	12/29/2002	$27,000,000	$4,000,000
CANMET CO_2 Consortium-O2/ CO_2 Recycle Combustion	Non-US	Natural Resources Canada-CANMET	09/29/1999	09/29/2002	$765,000	$35,000
An Integrated Modeling Framework for Carbon Management Technologies	Private Univ.	Carnegie Mellon University	08/13/2000	09/29/2003	$896,466	$717,172
International Collaboration on CO_2 Sequestration	Private Univ.	Massachusetts Institute of Technology	08/23/1998	10/22/2002	$950,000	$950,000
CO_2 Sequestration in Coalbed Methane Reservoirs	Private Univ.	University of Southern California	09/19/2001	09/18/2002	$50,000	$50,000
Development of Mesoporous Membrane Materials for CO_2 Separation	Private Univ.	Drexel University	08/30/2000	12/30/2002	$53,458	$50,000
Photoreductive Sequestration of CO_2 to Form C1 Products and Fuel	Nonprofit	SRI International Corporation	03/19/2002	03/18/2003	$124,967	$99,974

Project Title	Performer Type	Performer	Project Start Date	Project End Date	Total Estimated Cost	DOE Share
Development of Synthetic Soil Materials for the Reclamation of Abandoned Mine Sites	Nonprofit	Western Research Institute	04/09/1998	06/29/2003	$279,434	$139,717
Recovery of CO_2 in Advanced Fossil Energy	Nonprofit	Research Triangle Institute	07/14/1998	02/27/2002	$550,000	$550,000
CO_2 Capture From Flue Gas Using Dry Regenerable Sorbents	Nonprofit	Research Triangle Institute	08/30/2000	08/30/2003	$1,050,889	$812,285
The Potential of Reclaimed Lands to Sequester Carbon and Mitigate the Greenhouse Effect	Nonprofit	Western Research Institute	11/14/1999	09/29/2002	$0	$0
Application and Development of Appropriate Tools and Technologies for Cost-effective Carbon Sequestration	Nonprofit	The Nature Conservancy (TNC)	07/10/2001	07/09/2004	$2,023,597	$1,618,878
Feasibility of Large-Scale CO_2 Ocean Sequestration	Nonprofit	Monterey Bay Aquarium Research Institute	09/17/2000	09/29/2003	$1,106,409	$812,695
The University of Kansas Center for Research	Nonprofit	University of Kansas Center for Research	09/26/2000	12/20/2003	$3,307,515	$2,436,690
Zero Emissions Power Plants Using SOFCs and Oxygen Transport Membranes	Large Business	Siemens Westinghouse Power Corp. - Pittsburgh	05/31/2000	11/29/2002	$3,084,061	$2,311,108
CO_2 Capture Project	Large Business	BP Corporation North America Inc	07/10/2001	11/10/2004	$9,994,165	$4,995,000
R&D Entitled, "Large Scale CO_2 Transportation and Deep Ocean Sequestration"	Large Business	McDermott Technology, Inc. (MTI-OH)	07/14/1998	12/30/2001	$619,732	$619,732
The Removal and Recovery of CO_2 from Syngas and Acid Gas Streams in an IGCC Power Plant	Large Business	Tampa Electric Company	08/23/1998	04/23/1999	$112,950	$50,000
Evaluation of Oxygen Enriched Combustion Technology for Enhanced CO_2 Recovery	Large Business	McDermott Technology, Inc, (MTI-Lynchburg)	09/01/1999	08/30/2002	$99,985	$99,985
CO_2 Capture from Industrial Process Gases	Large Business	Air Products and Chemicals, Inc.	09/17/1998	05/17/1999	$70,143	$50,000
Fuel-Flexible Gasification-Combustion Technology for Production of H2 and Sequestration-Ready CO_2	Large Business	GE Energy and Environmental Research Corporation	09/18/2000	09/29/2003	$3,378,920	$2,500,000
Sequestration of CO_2 Gas in Coal Seams	Large Business	CONSOL Inc.	09/20/2001	12/30/2008	$9,269,333	$6,959,601
Advanced Oxyfuel Boilers and Process Heaters for Cost Effective CO_2 Capture and Sequestration	Large Business	Praxair, Inc.	09/23/2001	12/30/2005	$5,836,482	$4,085,537
Greenhouse Gas Emissions Control by Oxygen Firing in Circulating Fluidized Bed Boilers	Large Business	ALSTOM Power, Inc., US Power Plant Laboratories	09/26/2001	10/26/2004	$1,996,486	$1,597,189
CO_2 Hydrate Process for Gas Separation from a Shifted Synthesis Gas Stream	Large Business	Bechtel National Inc.	09/29/1999	12/30/2005	$9,076,621	$9,076,621
Land Application Uses of Dry FGD By-Products	For-profit Organization	Dravo Lime Company	07/22/1991	07/21/1999	$4,302,804	$1,341,125

Project Title	Performer Type	Performer	Project Start Date	Project End Date	Total Estimated Cost	DOE Share
CO_2 Selective Ceramic Membrane for Water-Gas-Shift Reaction with Simultaneous Recovery of CO_2	For-profit Organization	Media and Process Technology Inc.	08/30/2000	08/30/2003	$900,000	$720,000
Novel Composite Membrane and Process for Natural Gas Upgrading	For-profit Organization	Innovative Membrane Systems, Inc.	09/28/1999	06/29/2002	$512,248	$392,373
Evaluation of Multiple Product Power Cycles	Natl Lab	Argonne National Laboratory (ANL)	02/08/2000	09/29/2002	$400,000	$400,000
Zero Emissions Steam Technology Research Facility Study	Natl Lab	Lawrence Livermore National Laboratory (LLNL)	02/09/2001	03/24/2002	$2,400,000	$1,200,000
Developing an Atomic Level Understanding to Enhance CO_2 Mineral Sequestration Reaction	Natl Lab	Argonne National Laboratory (ANL)	02/15/2001	02/14/2002	$357,000	$357,000
Nonaqueous Biocatalysis Applied to Coal Utilization	Natl Lab	Idaho National Engineering and Environmental Laboratory (INEEL)	03/08/1998	09/29/2002	$130,000	$130,000
Whitings as a Potential Mechanism for Controlling Atmospheric CO_2	Natl Lab	Idaho National Engineering and Environmental Laboratory (INEEL)	03/08/1999	09/29/2002	$1,600,000	$1,600,000
Vortex Tube Design and Demo for the Removal of CO_2 from Natural Gas and Flue Gas	Natl Lab	Idaho National Engineering and Environmental Laboratory (INEEL)	04/14/2000	09/29/2002	$925,000	$625,000
CO_2 Separation Using a Thermally Optimized Membrane	Natl Lab	Los Alamos National Laboratory (LANL)	04/14/2000	04/13/2003	$1,215,360	$1,215,360
Continue Evaluation of Feasibility of CO_2 Disposal in a Deep Saline Aquifer in	Natl Lab	Battelle Columbus Laboratories	04/29/1998	02/27/1999	$99,995	$99,995
Natural Gas Vehicle Fuel from Landfill Gas	Natl Lab	Brookhaven National Laboratory (BNL)	04/30/2000	09/29/2003	$50,000	$50,000
Sequestration of CO_2 in a Depleted Oil Reservoir - LANL	Natl Lab	Los Alamos National Laboratory (LANL)	04/30/2000	09/29/2002	$1,053,000	$1,053,000
Geological Sequestration of CO_2: GEO-SEQ / ORNL	Natl Lab	Oak Ridge National Laboratory (ORNL)	04/30/2000	09/29/2002	$1,540,000	$1,540,000
Sequestration of CO_2 in a Depleted Oil Reservoir	Natl Lab	Sandia National Laboratories (SNL) - NM	04/30/2000	04/30/2003	$2,295,095	$2,295,095
GEO-SEQ Project	Natl Lab	Lawrence Berkeley National Laboratory (LBNL)	04/30/2000	09/29/2002	$14,550,000	$2,750,000
Geological Sequestration of CO_2: GEO-SEQ	Natl Lab	Lawrence Livermore National Laboratory (LLNL)	04/30/2000	09/29/2002	$1,500,000	$1,500,000
CO_2 Separation Using Thermally Optimized Membranes-Nanocomposite Development	Natl Lab	Idaho National Engineering and Environmental Laboratory (INEEL)	05/14/2000	05/13/2003	$185,000	$185,000
Evaluation of CO_2 Capture, Utilization, and Disposal Options	Natl Lab	Argonne National Laboratory (ANL)	05/21/1992	04/29/1997	$815,000	$815,000

Project Title	Performer Type	Performer	Project Start Date	Project End Date	Total Estimated Cost	DOE Share
Experimental Evaluation of Chemical Sequestration of CO_2 in Deep Saline Formations	Natl Lab	Battelle Columbus Laboratories	07/09/1998	09/29/2004	$596,649	$596,649
Enhancement of CO_2 Emissions Conversion Efficiency by Structured Microorganisms	Natl Lab	Idaho National Engineering and Environmental Laboratory (INEEL)	07/31/1999	09/29/2002	$327,000	$327,000
Biomineralization for Carbon Sequestration	Natl Lab	Oak Ridge National Laboratory (ORNL)	07/31/1999	09/29/2002	$1,000,000	$1,000,000
Enhanced Practical Photosynthesis Carbon Sequestration	Natl Lab	Oak Ridge National Laboratory (ORNL)	07/31/1999	09/29/2002	$172,000	$172,000
Modification/Development of Carbon Fiber Composite Molecular Sieve for Removal of CO_2	Natl Lab	Oak Ridge National Laboratory (ORNL)	07/31/2001	12/30/2002	$344,000	$172,000
CO_2 Hydrate Process for Gas Separation from a Shifted Synthesis Gas Stream	Natl Lab	Los Alamos National Laboratory (LANL)	08/14/1999	01/29/2005	$5,230,000	$5,230,000
Renewable Hydrogen Production for Fossil Fuel Processing	Natl Lab	Oak Ridge National Laboratory (ORNL)	09/01/1998	09/29/1999	$22,000	$22,000
CO_2 Sequestration by Mineral Carbonation Using a Continuous Flow Reactor	Natl Lab	Albany Research Center (ALRC)	09/29/2001	09/29/2003	$1,300,000	$1,300,000
Evaluation of CO_2 Capture/Utilization/Disposal Options	Natl Lab	Argonne National Laboratory (ANL)	09/30/1997	09/29/2002	$544,000	$544,000
Mineral Carbonation - Preliminary Feasibility Study	Natl Lab	Albany Research Center (ALRC)	09/30/1997	11/29/2001	$2,145,700	$945,700
Development of Hydrogen Separation and Purification Membranes	Natl Lab	Sandia National Laboratories (SNL) - CA	09/30/1998	09/29/2002	$594,000	$594,000
Exploratory Measurements of Hydrate and Gas Compositions	Natl Lab	Lawrence Livermore National Laboratory (LLNL)	09/30/1998	09/29/2002	$500,000	$500,000
Screening of Marine Microalgae for Maximum CO_2 Biofixation Potential	Natl Lab	Pacific Northwest National Laboratory (PNNL)	09/30/2000	09/29/2002	$200,000	$200,000
Advanced Plant Growth	Natl Lab	Los Alamos National Laboratory (LANL)	09/30/2000	11/29/2001	$880,000	$880,000
Ecosystem Dynamics	Natl Lab	Los Alamos National Laboratory (LANL)	09/30/2000	11/29/2001	$1,705,000	$1,145,000
Enhancing Carbon Sequestration & Reclamation of Degraded Lands with Fossil Fuel Combustion Byproducts	Natl Lab	Oak Ridge National Laboratory (ORNL)	12/31/1999	12/30/2001	$1,067,000	$1,067,000
Full-Scale Bioreactor Landfill	County Agcy	Yolo County	08/01/2001	07/31/2004	$1,748,103	$563,000
Fossil Fuel Derivatives with Reduced Carbon	tbp	Applied Sciences, Inc.	09/30/1998	09/29/1999	$99,845	$99,845
Total					$161,998,484	$95,624,581

Appendix B
DESCRIPTION OF THE NATIONAL COAL COUNCIL

In the fall of 1984, The National Coal Council was chartered and in April 1985, the Council became fully operational. This action was based on the conviction that such an industry advisory council could make a vital contribution to America's energy security by providing information that could help shape policies relative to the use of coal in an environmentally sound manner which could, in turn, lead to decreased dependence on other, less abundant, more costly, and less secure sources of energy.

The Council is chartered by the Secretary of Energy under the Federal Advisory Committee Act. The purpose of The National Coal Council is solely to advise, inform, and make recommendations to the Secretary of Energy with respect to any matter relating to coal or the coal industry that he may request.

Members of the National Coal Council are appointed by the Secretary of Energy and represent all segments of coal interests and geographical disbursement. The National Coal Council is headed by a Chairman and a Vice-Chairman who are elected by the Council. The Council is supported entirely by voluntary contributions from its members. To wit, it receives no funds whatsoever from the Federal Government. In reality, by conducting studies at no cost which might otherwise have to be done by the Department, it saves money for the government.

The National Coal Council does not engage in any of the usual trade association activities. It specifically does not engage in lobbying efforts. The Council does not represent any one segment of the coal or coal-related industry nor the views of any one particular part of the country. It is instead to be a broad, objective advisory group whose approach is national in scope.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the requested study. The first major studies undertaken by the National Coal Council at the request of the Secretary of Energy were presented to the Secretary in the summer of 1986, barely one year after the start-up of the Council.

Appendix C
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Appendix F
CORRESPONDENCE BETWEEN THE U.S. DEPARTMENT OF ENERGY & THE NATIONAL COAL COUNCIL

The Secretary of Energy
Washington, DC 20585

September 24, 2002

Mr. Wes Taylor
Chairman, The National Coal Council
1730 M Street, NW
Washington, DC 20036

Dear Mr. Taylor:

The National Coal Council (NCC) has provided valuable advice and guidance on a continuing basis on general policy matters related to coal.

In a previous report entitled "*Research and Development Needs for the Sequestration of Carbon Dioxide as Part of a Carbon Management Strategy,*" the NCC recommended: "...the U.S. Government...in partnership with the entire coal industry, implement an even fuller and more aggressive carbon management program with a major component being research and development of cost-effective CO^2 sequestration technologies." Additionally, recent NCC studies have demonstrated the importance of increased energy efficiency from coal-fired power plants in reducing greenhouse gas emissions.

This Administration has implemented a three-pronged strategy to address climate change: increased energy efficiency, use of lower and no-carbon fuels, and carbon sequestration. Given the President's strong endorsement of voluntary greenhouse gas reductions, the major commitments that various industry groups and individual companies have made to promote the President's goals, and technological improvements in coal-fired generation and sequestration technology, I request that the NCC now prepare an update to this report. For example, several companies have partnered with the Department of Energy to evaluate the effectiveness and economics of sequestering carbon. These and other public-private partnerships should be highlighted in this report, as well as future partnership opportunities. Also, your perspective on how voluntary approaches to reduce greenhouse gas emissions could be best achieved would also be very valuable.

We believe that your membership represents a broad spectrum of senior level industry, State, and public interest organizations and is well positioned to carry out this request.

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We also believe that the updated report will serve as a carbon management blueprint for industry and act as a catalyst to promote additional public-private partnerships to support voluntary reduction of greenhouse gases and carbon sequestration.

I am designating Mr. Robert G. Card, Under Secretary for Energy, Science and Environment, and Mr. Carl Michael Smith, Assistant Secretary for Fossil Energy, to represent me in the conduct of this important study. I offer my gratitude to the Council for its efforts to assist the Department in defining the scope of this study request. We look forward to receiving this report when completed.

Sincerely,

Spencer Abraham

Spencer Abraham

Appendix G
CORRESPONDENCE
FROM INDUSTRY EXPERTS

Comments on R&D Needs for Coal Related Global GHG Management (re Draft NCC Report)

Alex Green, University of Florida, aesgreen@ufl.edu

Essential Comment: Some attention was given to natural processes in the Terrestrial Sequestering section of the May 2000 and in this NCC report. However, the writer believes that the forestry-agriculture component of coal related GHG management deserves more R&D emphasis via two thrusts and possible combinations of these thrusts:

T1) Co-utilization of some CO_2 neutral biomass with coal in electrical generation.

T2) Increasing natural carbon dioxide sequestering by restoring soil organic carbon in agriculturally depleted areas, by fostering the growth of trees and by constructing long lived wooden or carbon structures

Background: Nature over billions of years developed photosynthesis and plants that extract CO_2 from the atmosphere and convert it to biomass via reactions such as

$$5CO_2 + 5H_2O + \text{solar energy} \rightarrow C_5H_{10}O_5 + 5\,O_2$$

The use of biomass for energy, human-kinds oldest technology, simply completes a CO_2 neutral cycle:

$$C_5H_{10}O_5 + 5O_2 \rightarrow 5CO_2 + 5H_2O + \text{heat energy}$$

Nature, has also developed natural biological and physical processes (coalification) that transform biomass successively into peat, lignite, sub-bituminous bituminous and anthracite coal. Somewhat similar natural de-oxygenating processes changed some types of plant matter into oil and natural gas. The several hundred million year deposits of coal, oil and natural gas since the Carboniferous age became a vast storehouse of underground solar energy. However, since the industrial revolution human withdrawals from this bank have been at very high rates and oil and natural gas deposits will probably be depleted in few decade. However, since coal, widely distributed on the globe, should last two or three centuries, it is prudent, to use this resource in eco-friendly ways.

IC on CDF (T1): An International Conference (IC) on Co-utilization of Domestic Fuels (CDF) was held at the University of Florida on February 5 and 6, 2003. The main purpose of the CDF conference was to examine various CDF technologies and their energy, environmental and economic benefits. Particular attention was given to co-use of coal with biomass (wood, agricultural residues, municipal solid waste, bio-solids, etc.) in eco-friendly thermo-chemical reactors for electrical generation, waste disposal and for production of gaseous fuels, liquid fuels and chemicals.

The CDF conference participants included 8 senior academics from abroad 12 from the USA, 32 utility persons or persons from engineering firms supporting utilities, 10 from government agencies or organizations advising government agencies (including NCC's Bob Beck and Irene Smith, a CDF expert from UK), one Sierra Club representative, and 3 experts from a forestry conference then assembled in Gainesville. Table 1 gives the list of conference sponsors.

To set the stage for discussions at the CDF conference three books [1-3], two recent reports [4,5] and a compact disc [6] of a Florida report on renewables in electrical generation were distributed at registration. The CDF conference proceeding are available in CD form and selected papers will be published in a special issue of IJPES.[7]

Global Aspects: The GHG emissions problem is a global one and proposed solutions must be examined from a global perspective with serious consideration of the policies of other countries on GHG emissions. . Figure 1 shows the global fuel shares in % (see www.iea.org). Since it is important to be mindful of the location of the decimal place note that over the globe, renewables (non-GHG energy sources) are at the same order of magnitude as oil, coal, natural gas and nuclear. Among the renewables, combustible renewable and waste (CRW) are at 11% and hydro at 2.3% whereas solar is only at 0.04% and wind at 0.03 %..

Table 1 lists the total primary energy supply (TPES) for various regions of the world or country groupings. The TPES in the 2nd column are in Mtoe (Mtoe=one million tons of oil equivalent = $42*10^{15}$ joules = 0.040 quads = 40.10^{12} BTU) The Organization for Economic Co-operation and Development (OECD) countries are here subdivided into OECD-Pac (Pacific for Japan, Korea, Australia and New Zealand), OECD-Europe, and OECD-NA (North America for USA, Canada and Mexico). Column 2 gives the regions TPES. Column 3 gives the percentage of the TPES that is combustible renewable and waste (CRW). Column 4 gives the percentage of the other renewable components (hydro-electric, geothermal, wind, solar and tide/wave/ocean).

The large CRW levels for Africa, Asia, China, and Latin America in Table 1 reflect large residential consumption of biomass for home cooking and heating. In view of population growth in these geographic areas the ability of annual biomass resources to keep up with these residential needs is a matter of concern. In these regions CDF technologies might be developed in which coal or natural gas is used in small percentages to enhance the efficiency of biomass utilization. On the other hand in developed regions where CRWs are now in low percentages a proven CO_2 management strategy would be to rebuild the use of biomass to a larger percentage of TPES.

The extra row at the bottom of Table 2 gives specific data for the USA. The USA with 4.6% of the global population accounts for about 24% of the global energy consumption and some 24% of global CO_2 emissions. Developing and fostering practical CDF systems in the USA to facilitate greater use of CO_2 neutral biomass energy could help the USA's balance its military leadership by environmental leadership.

The USA has considered returning to the use of wood and other forms of biomass since the oil crises of 1973. Residential use of wood increased strongly nationwide and biomass generating capacity gradually built up to 6 Gigawatts by 1990. California with favorable legislation led the way, however, by 1995 half of the California biomass power industry shut down. Today biomass is regaining attention both as a GHG management and for energy security. A number of states are mandating or otherwise encouraging the use of renewables in the electric generating mix. In most geographic locations biomass stands out as the only renewable that can significantly be expanded in the next decade or two via CDF technologies.

Table 3 illustrates representative solid fuel properties that resulted from the "coalification" process. Columns 2-4 give representative ultimate analyses in weight % corrected to apply for dry, ash, sulfur and nitrogen free feedstock. The 5th and 6th columns give total volatiles (V_T) and fixed carbon (FC) also in wt%.. The 7th column gives heating value (HVs in MJ/Kg). The 8th and 9th columns give energy density, (E/vol, in MJ/liter) and estimated relative char reactivities. Biomass has advantages of high volatility and char reactivities that make conversions from solids to more useful gaseous or liquid fuels relatively easy. On the other hand coals have advantages of global abundance, high HVs, high energy densities and other features that fosters low costs. Technologies for co-utilizing biomass with coal enable the useful properties of one fuel to assist the thermal processing of the other.

Since 1992 the European Union has actively pursued co-utilization of coal and biomass [8-10], (see additional references in [4]) as a means of bringing more advanced technologies to bear on the use of biomass, and as a CO_2 mitigation measure. The costs and availability of biomass in various parts of the globe have been studied extensively in this context [11]. A recent European Union White Paper [12] projects the growth of biomass use from 3.1% of their total energy in 1995 to 8.5% in 2010. By taking advantage of regions with abundant sunshine and rain the USA could easily match or exceed this goal. To some experts our emphasis on R&D towards zero emission technologies or hydrogen as the solution of our emission problems is distracting the USA from pursuit of doable near term measures that can benefit the environment and the economy and restore USA's environmental leadership. .

Terrestrial CO2 Sequestering (T2): As summarized on page 11 of the May 2000 NCC report and on page 16 of this report and in the literature [13] GHG management can be fostered by restoring forests, soil organic carbon (SOC) and the use of long lived wood or carbon structures. The possibility of restoring SOC with mildly oxidized low rank coal is an R&D area that seems worth pursuing [14]. Going from lignite back to peat and other modest manipulations of nature's coalification processes does not seem as remote as zero-emissions. Research on optimum combinations of T1 and T2 is sorely needed. In R&D projects, in contrast to demonstration projects, we appear to be overlooking the possibility of modest improvements upon nature's ways in favor of "all or nothing" moon -shots type methods. Getting plant people together with the coal people to examine and possibly improve upon of nature's ways is probably the fastest way of bringing more renewables into our energy mix and also enhancing carbon sequestration.

Table 4 list why "the farmers and the miners should be friends" a theme that has been almost as hard to sell as getting the farmers and the cow-men to be friends after the Oklahoma land-rush.

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[3] A. Green and W. H. Smith, Eds. Acid Deposition Causes and Effects Eds. Government Institutes Inc.,Rockville, MD

[4] A. Green, *A green alliance of biomass and coal (GABC)* . Appendix F. in Increasing coal –fired generation through 2010: challenges & opportunities, Report of the *The National Coal Council (NCC)*, May 2002: (also published in Proc. of the 28th Intern. Conf. Clearwater FL March 2003, 689-700)

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[13] R. Lai et al.(1998) Potential of US Cropland to Sequester Carbon and Mitigate the Greenhouse Fffect, Sleeping Bear Press , Chelsea, MI

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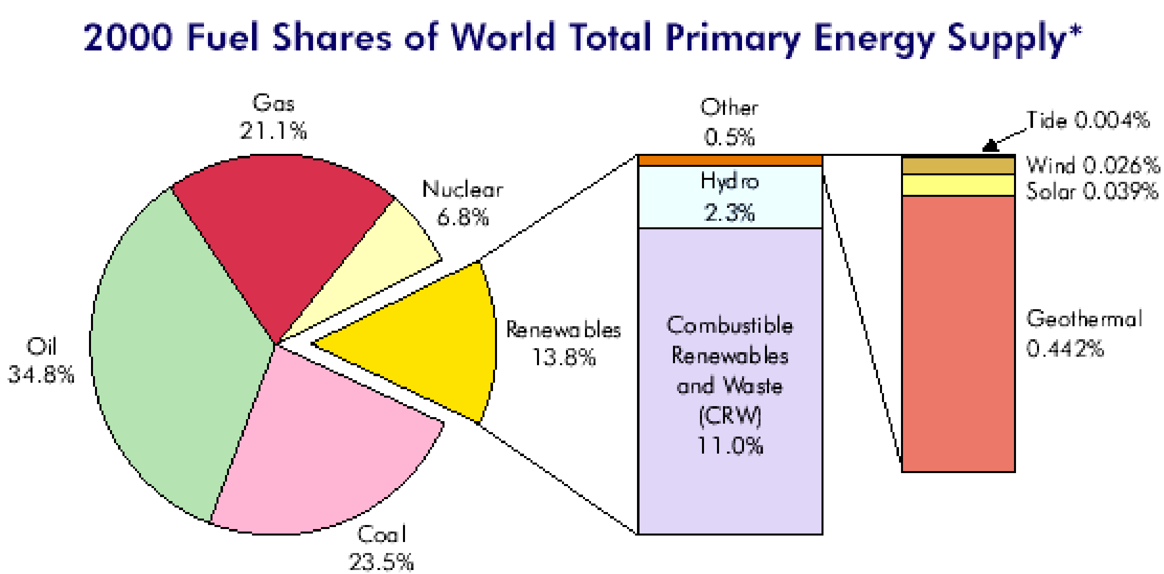

Table 1: List of Sponsors

1) United States Department of Energy
2) Mick A. Naulin Foundation
3) College of Engineering, University of Florida
4) Division of Sponsored Research, University of Florida
5) School of Forest Resources and Conservation,
6) Public Utility Research Center, University of Florida
7) Florida Agricultural Experiment Station
8) National Rural Electric Cooperative Association
9) Triangle Consulting Group
10) Science and Technology Corporation
11) Green Liquids and Gas Technologies
12) Fuel and Combustion Technology Division, ASME
13) Coal, Biomass and Alternative Fuels Committee, IGTI
14) Florida Department of Agriculture & Consumer Services, Division of Forestry
15) International Association of Science and Technology for Development

Table 2: Total Primary Energy and Renewable Indicators

Region	TPES (Mtoe)	CRW (%)	Other (%)
Africa	508	49.6	1.3
Latin America	456	17.1	10.8
Asia	1123	31.5	2.5
China	1158	18.5	1.7
Former USSR	921	1.2	2.1
Middle East	380	0.3	0.5
Non-OECD-Eu	95	5.3	4.6
OECD Europe	1765	3.9	3.1
OECD Pacific	847	1.7	2.2
OECD NA	2705	3.6	2.8
Total	**9957**	**11.0**	**2.8**

USA	2300	3.4	1.6

Table 3. Solid fuel properties along coalification path

Rank	Ultimate Analysis			Proximate Analysis			Other properties	
Name	C	H	O	VT	FC	HV	E/vol	React
Cellulose	44	6	50	88	12	10	9	1600
Wood	49	7	44	81	19	18	11	500
Peat	60	6	34	69	31	23	18	150
Lignite	70	5	25	58	42	27	27	50
Sub Bitum	75	5	20	51	49	30	36	16
Bitum	85	5	10	33	67	33	49	5
Anthracite	94	3	3	7	93	34	58	1.5

Table 4: Why "the farmers and the miners should be friends"

I. <u>What can Biomass do for Coal</u>

A) Co-firing Biomass with Coal
1) Lower CO_2, SO_2 and NOx emissions
2) Foster renovation and ecofriendly use of coal facilities
3) Foster IGCC, IG-cogen, CHP and chemical factories.

B)Co-gasifying Biomass with Coal
1) Facilitate conversion to useful gases and liquids
2) Provide important environmental roles for coal
3) Facilitate capture of toxics (mercury, arsenic…)

C) CO_2 Sequestration, Nature's Way
1) Federal, state land reforestation, new parks
2) Interstate highway plantings
3) Urban forestation (elms)
4) Wood buildings and long lived carbon products
5) Restore agriculturally depleted lands

D) Phytoremediation
1) Restoration of mined lands
2) Foster phyto-mining
3) Remediate toxic sites

II. <u>What can Coal do for Biomass?</u>

A. Make Opportunity fuels competitive
1) Lower capital cost of co-utilization (co-firing)
2) Foster use with turbine generators (co-gasifying)

B. Provide economic agricultural alternatives
1) Energy crops
2) Use of agricultural residues
3) Disposition of problem plant matter
4) Overcome biomass-use problems

<u>III. What can friends do for the Globe?</u>

A. Foster greening of planet earth
1) Lower CO_2, pollution and toxic emission problems
2) Foster advanced environmental technologies
3) Foster phyto-remediation, phyto-mining

B. Facilitate economic recovery
1) Develop a biomass market and supply infrastructure
2) Foster biomass to liquid fuels and chemicals
3) General development of fuel co-utilization

From the Musical Oklahoma

The farmer and the miner should be friends
Oh the farmer and the miner should be friends
One likes to plant a tree, the other likes to set coal free
but that's no reason they caint be friends

Energy folks should stick together
Energy folks should all be pals
Miners dance with farmers daughters
Farmers dance with miners gals
Repeat

Appendix H
ACKNOWLEDGEMENTS

The members of the Council wish to acknowledge, with sincere thanks, the special assistance received from the following persons in connection with various phases of the development of this report:

Julie Clendenin, ***Editor***

Pam Martin, ***NCC Staff***

Lorna Schlutz, ***CONSOL Energy, R&D***

David Surber, ***Make Peace With Nature TV Show***

LK

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

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217/785-4140
TDD 217/782-9143

March 30, 2004

Docket ID No. OAR 2003-0053
Air Docket
U.S. Environmental Protection Agency
Mail Code 6102T
1200 Pennsylvania Ave, NW
Washington, DC 20460

Re: Proposed Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Interstate Air Quality Rule) January 30, 2004, 69 *Federal Register* 4566

To Whom It May Concern:

The Illinois Environmental Protection Agency (Illinois EPA) appreciates this opportunity to comment on the U.S. Environmental Protection Agency's (U.S. EPA's) "Proposed Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone" referred to herein as the Interstate Air Quality Rule. These comments are provided to supplement the testimony I presented on behalf of the Illinois EPA at the public hearing held in Chicago on February 26, 2004.

Illinois EPA fully supports U.S. EPA's efforts to reduce the levels of transported pollutants. We urge U.S. EPA to move forward with an aggressive national control program to reduce interstate transport of ozone and fine particulate matter. We have several concerns regarding the shortcomings of the proposed Interstate Air Quality Rule, and we urge U.S. EPA to amend its proposed rules in a manner that will provide greater regional reductions of nitrogen oxides (NOx) and sulfur dioxide (SO_2) in a time frame that is consistent with expected attainment deadlines for both the 8-hour ozone and fine particulate matter National Ambient Air Quality Standards (NAAQS). Illinois EPA considers further reduction of these emissions from fossil fuel fired power plants to be practicable, warranted, cost-effective and long overdue. Further, Illinois EPA is concerned that the proposed Interstate Air Quality Rule omits important sources that contribute to interstate pollutant transport.

Attainment of the NAAQS

Illinois has recently provided recommendations to U.S. EPA to designate portions of the Chicago and East St. Louis metropolitan areas as nonattainment areas for the fine particulate matter NAAQS and the 8-hour ozone NAAQS. It is likely that these areas will be required to attain each of these air quality standards by 2010. Ambient air quality measurements at rural monitors in Illinois clearly show that there are significant background concentrations of these pollutants, at levels that approach the NAAQS, which are the result of transport. The high levels of these pollutants will make it virtually impossible for Illinois to attain the NAAQS by the statutory deadlines without a strong regional, and even national, approach to reducing them. U.S. EPA's own technical analysis used to support this rule shows that even with the proposed controls, portions of the Chicago metropolitan area will not meet either the fine particulate matter or 8-hour ozone NAAQS by 2015, five years after the required attainment date. We believe that greater reductions in transported pollutants can and should be required, and that the reductions must occur soon enough for states to include them in their plans to attain the 8-hour ozone and fine particulate matter standards by the proposed federal attainment deadlines.

Although U.S. EPA has not finalized its 8-hour ozone implementation policy guidance or issued its PM2.5 implementation policy guidance, it appears that 2010 is the likely attainment year for areas in Illinois that are not meeting the 8-hour ozone and fine particulate matter standards. In our opinion, supported by U.S. EPA's modeling, the Interstate Air Quality Rule does not provide sufficient emission reductions to reduce the impacts of interstate transport by 2010, especially for ozone. Consequently, the Illinois EPA recommends that state emission budgets for NOx for electrical generating units, or EGUs, be tightened during the ozone season. The NOx SIP Call requires a regional NOx emission cap of 515,400 tons per ozone season. The Illinois EPA recommends that an emissions cap be retained for the ozone season for the NOx SIP Call region, and that the level of the cap be reduced to 410,000 tons per ozone season beginning in 2010.

Illinois believes that the Interstate Air Quality rule should apply to the 30-state region plus the District of Columbia alternative proposed by U.S. EPA for NOx and also for SO_2. Based on a 30-state region plus D.C., the NOx emission cap for EGUs should be set at 1.45 million tons, and the SO_2 emission cap should be set at 3.5 million tons annually by 2010. This level of reduction would still fall within the range of reductions considered "highly cost effective" under the NOx SIP Call (*See, generally*, 63 FR 57399-47402 (October 27, 1998)).

Subpart 1 of the Clean Air Act provides for the possibility of extending the fine particulate matter attainment date until 2015. Illinois EPA, therefore, recommends that a second phase of NOx and SO_2 emission reductions should occur by that year. Accordingly, Illinois EPA recommends that the 30-state and D.C. region annual NOx emissions cap for EGUs be reduced to a level of 1.26 million tons on an annual basis beginning in 2015, and that SO_2 emissions from EGUs be capped to a level of 2.11 million tons annually.

Control of Non-EGUs

U.S. EPA did not include non-EGUs in the proposed Interstate Air Quality Rule NOx emissions cap, and the Illinois EPA strongly urges U.S. EPA to reconsider its proposal in this regard. U.S. EPA included certain categories of non-EGUs in the NOx SIP Call and in doing so, made the determination that seasonal reductions of NOx based on an emission limit of 0.15 lbs NOx/mmBtu would be highly cost effective. Pursuant to the NOx SIP Call, Illinois' non-EGUs are required to reduce their NOx emissions on a seasonal basis by 7,284 tons. If U.S. EPA included the non-EGUs in the Interstate Air Quality Rule at the same level of control required pursuant to the NOx SIP Call, then Illinois' non-EGUs would be required to control their NOx emissions on an annual basis, resulting in an additional reduction of 10,092 tons of NOx emissions per year. We recommend that U.S. EPA include highly cost effective NOx controls at non-EGUs in the Interstate Air Quality Rule.

We also urge U.S. EPA to propose, as part of this rulemaking, controls on NOx emissions from stationary internal combustion engines and to require these controls on an annual basis. U.S. EPA's actions with regards to this source category as part of Phase II of the NOx SIP Call are long overdue. In addition, this rulemaking should also require that existing NOx controls on cement kilns, imposed as part of the NOx SIP Call, be applied on an annual basis.

Emissions Trading

Illinois has been recognized as a leader in the area of emissions trading, and based on our experience with a number of emissions trading programs, we concur with the concept of an interstate trading program to be administered as part of the Interstate Air Quality Rule. We are concerned, however, that the banking of the Acid Rain Program SO_2 emission allowances may delay full implementation of controls and may hinder the states' ability to meet their attainment deadlines. We urge U.S. EPA to severely limit the number of SO_2 allowances that can be banked.

Illinois supports the integration of the trading program under the Interstate Air Quality Rule with the existing NOx SIP Call trading program, provided that the NOx SIP Call emission caps are retained and reduced during the ozone season until 2015. A well-designed and properly implemented emissions trading program, including both EGUs and non-EGUs in a combined program, will not only help ensure that emission reductions are cost effective but will actually promote greater emission reductions, as financial resources are directed to sources with the greatest emission reduction potential. We do not support interpollutant trade under any circumstances.

We recommend that both NOx and SO_2 allowances be given to the states to be allocated at the States' discretion, including the discretion to allocate some of their allowances for energy efficiency purposes.

Regional Haze Program Consistency

While it is clear that additional reductions from EGUs are warranted and achievable, we must take all available steps to provide the electric power industry with a reasonable degree of certainty regarding future regulatory requirements. The industry must be given the opportunity to plan for the most cost-effective set of compliance options. Thus, U.S. EPA should ensure that the Interstate Air Quality Rule conforms to the Regional Haze requirements of the Clean Air Act and is so structured that it will meet the requirements that U.S. EPA will ultimately propose to address Regional Haze, including requirements for Best Available Retrofit Technology (BART).

Acid Rain Allowances

On page 4626 of the proposal, U.S. EPA states that SIPs may need to require the retirement or elimination of certain Title IV allowances under the Acid Rain Program. This obligation raises several issues. While most states have the authority to adopt more stringent SO_2/NOx emission limits, or can require compliance with their own trading programs established for purposes that are different from the Acid Rain program, it is not clear what authority states would have to require retirement of allowances issued by U.S. EPA under Title IV. U.S. EPA should clarify in the final rule how a state can require a source to retire or eliminate allowances that have been given under the federal Acid Rain Program.

Section 126

U.S. EPA included language in the proposal regarding section 126 petitions. Illinois EPA agrees that an aggressive control program that eliminates significant contributions from interstate transport would be the preferred remedy, but as stated previously, we are concerned that this rule, as proposed, will not resolve all interstate transport problems. However, if U.S. EPA proceeds to adopt an Interstate Air Quality Rule, there should be a moratorium on Section 126 petitions until states have completed their attainment demonstrations, and can demonstrate that further regional reductions are required. We recommend that this moratorium should be contingent upon states' compliance with the rule as adopted.

Technical Comments

While we applaud the efforts of U.S. EPA staff to evaluate the impact of the proposed Interstate Air Quality Rule through photochemical modeling, we must note that the U.S. EPA modeling would fall far short of being acceptable as a SIP submittal from a State. We support the technical comments prepared by the Lake Michigan Air Directors Consortium (LADCO) on behalf of its member States. A copy of their comments is included as an attachment.

The Illinois EPA does not support the use of growth factors derived from the IPM model and acknowledges U.S. EPA's efforts to develop a more equitable approach. However, U.S. EPA's Technical Support documentation does not adequately explain the methodology employed in this proposal. Consequently we are unable to understand how the heat input values used to calculate states' budgets were derived. We urge U.S. EPA to provide a more thorough discussion of its methodology, and provide another opportunity for states to comment on the accuracy of the calculations.

The Illinois EPA appreciates this opportunity to comment on the U.S. EPA's Interstate Air Quality Rule. If you have any questions regarding our comments, please contact Laurel L. Kroack, Manager of the Division of Air Pollution Control, at 217/785-4140.

Sincerely,

Renee Cipriano

Renee Cipriano
Director

Attachments

March 22, 2004

Lake Michigan Air Directors Consortium

Technical Comments: Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Interstate Air Quality Rule)

(1) LADCO Modeling: To assess the impact of the proposed emission reductions, LADCO performed air quality modeling. A summary of this modeling is provided in the attached report ("Interstate Air Quality Rule: Modeling Analysis", March 22, 2004). The key findings of this modeling are as follows:

- The proposed SOx and NOx emission reductions, in combination with expected federal and state controls, will reduce ozone and fine particle concentrations, and improve visibility levels in the eastern U.S.
- Although future year design values are estimated to below the ambient standards in many counties, residual ozone and fine particle nonattainment problems exist in a number of urban areas in the eastern U.S.
- Future year visibility levels are estimated to be on (or below) the "glide path" towards natural conditions in many Class I areas in the eastern U.S.
- The modeling results are qualitatively similar to those reported by USEPA in their Federal Register notice and "Technical Support Document for the Interstate Air Quality Rule, Air Quality Modeling Analysis" (January 2004).

It should be noted that there are several limitations with this analysis, including less than desirable model performance for various $PM_{2.5}$ species (e.g., nitrates and organics), concerns with emission estimation methodologies for several source categories, and use of growth and control factors of unknown quality. As such, the modeling results are not definitive and should only be viewed as qualitative in nature (i.e., approximating the improvement in air quality, but not defining a specific level of [future] air quality). More reliable modeling will be performed over the next couple of years to support SIP development. Nevertheless, some modeling now to assess the air quality benefits of the proposed rule is appropriate both to serve as the basis for commenting on the proposed rule and helping direct initial control strategy work.

(2) Use of USEPA Modeling Guidance: We support use of USEPA's modeling guidance and encourage USEPA to finalize these draft documents (i.e., "Draft Guidance on the Use of Models and Other Analyses in Attainment Demonstrations for the 8-Hour Ozone NAAQS", EPA-454/R-99-004, May 1999 and "Guidance for Demonstrating Attainment of Air Quality Goals for $PM_{2.5}$ and Regional Haze", draft 2.1, January 2, 2001).

We also wish to make several comments related to this guidance:

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- We encourage USEPA to follow its modeling guidance in conducting its air quality analyses. With the respect to the modeling performed for the proposed rule, for example, it is not clear that USEPA has followed its own guidance for model selection, episode selection, emissions inventory development, and evaluating model performance. USEPA even suggested that its analyses are not sufficient to demonstrate attainment (e.g., Page 4599: "It is not feasible at this time to identify the levels of emissions reductions from sources of regional transport and reductions from local sources that will lead to attainment of the PM standards. Much technical remains as States develop their SIPs, including improvements in local emissions inventories, local area and subregional air quality analyses, and impact analysis of the effects and costs of local controls.")

- We encourage USEPA to provide software programs for applying its attainment and reasonable progress tests. USEPA is apparently using in-house software, which it is unable to provide to states for their use in calculating future year design values for ozone and $PM_{2.5}$. To ensure consistency (and avoid misinterpretations) in applying USEPA's tests, USEPA should make the attainment software programs available. This is necessary to enhance the credibility of the state attainment demonstrations.

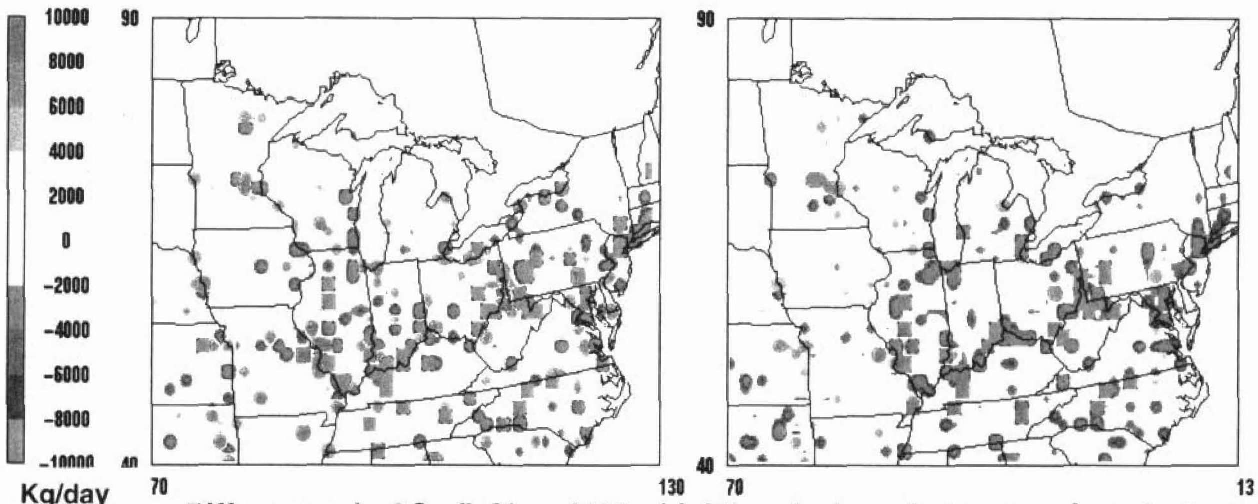
- Although we agree with USEPA's use of the models in a relative way to assess the air quality impact of the proposed emission reductions, we believe that additional analysis should be conducted to justify such use of the models. USEPA stated that the negative effects of relatively poor model performance for some $PM_{2.5}$ chemical species is mitigated to some extent by using the model predictions in a relative way. To add credibility to the modeling analysis, we believe that USEPA's performance evaluation should consider not just the absolute model results, but the relative results, as well. USEPA's modeling guidance recommends "…evaluating model performance in a way which is closely related to how models are used to support attainment and reasonable progress demonstrations." These diagnostic evaluations are identified by USEPA as being more important than operational evaluations, which is what USEPA has done as part of the modeling for the proposed rule. We, therefore, encourage USEPA to conduct a relative model performance evaluation.

- Finally, USEPA used one approach for estimating future year design values for ozone and another approach for $PM_{2.5.}$ We encourage USEPA to resolve this discrepancy and adopt a consistent approach for both ozone and $PM_{2.5}$.

(3) Modeling Inventory: We have concerns about the use of the 1996 National Emissions Inventory (NEI) as the basis for USEPA's modeling inventory. In particular, we believe that this inventory is out-dated, and that more current information is available and should be used (e.g., USEPA's 1999 NEI data).

Additional inventory concerns are as follows:

- EGUs: For EGUs, USEPA used state-level adjustment factors for deriving the 2001 "proxy" inventory, and possibly for the 2010 and 2015 future year inventories. This approach treats all plants in the state the same, which may or may not be the case, in light plant-by-plant differences in compliance with Title IV and the NOx SIP call. We believe that the plant-level data from IPM should be used instead. The plots below show the difference in emissions for these two cases.



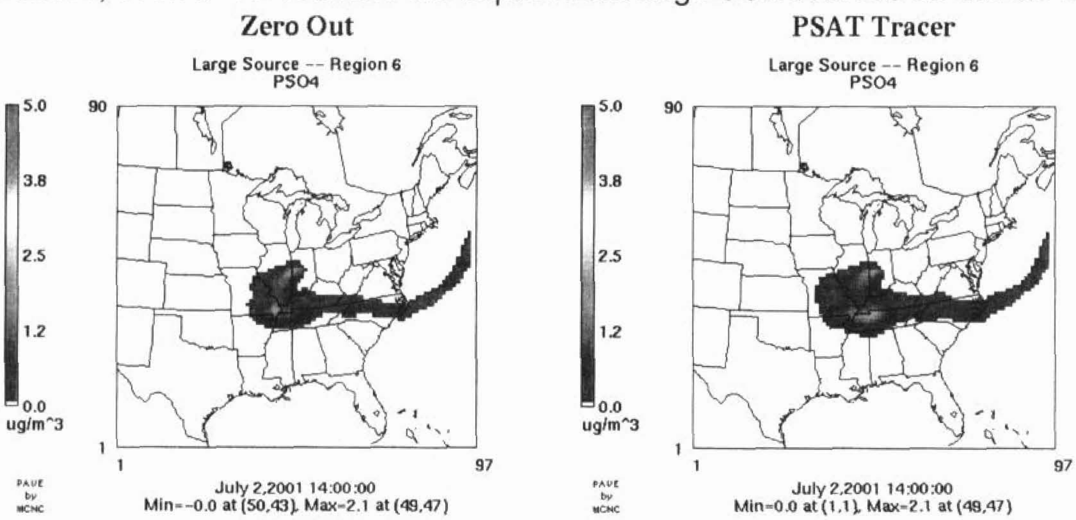
Differences in SOx (left) and NOx (right) emissions between using plant-level and state-level adjustments for the 2010base inventory

- Proposed EGU Caps: USEPA should clarify the level of emission reductions expected in 2010 and 2015 associated with the proposed emission caps. Based on USEPA's modeling files, it appears that the USEPA expects the annual EGU emissions in the affected states to be 5.4M tons (not 3.9M tons) and 1.7M tons (not 1.6M tons) for SOx and NOx, respectively, in 2010; and 4.7M tons (not 2.7M tons) and 1.5M tons (not 1.3M tons) for SOx and NOx, respectively, in 2015. The higher emissions modeled by USEPA account for banked emissions under the Title IV program. Given the significance difference in air quality due to the banked emissions (as demonstrated by our modeling), USEPA should acknowledge the true (lesser) emission reductions expected from the proposed rule.

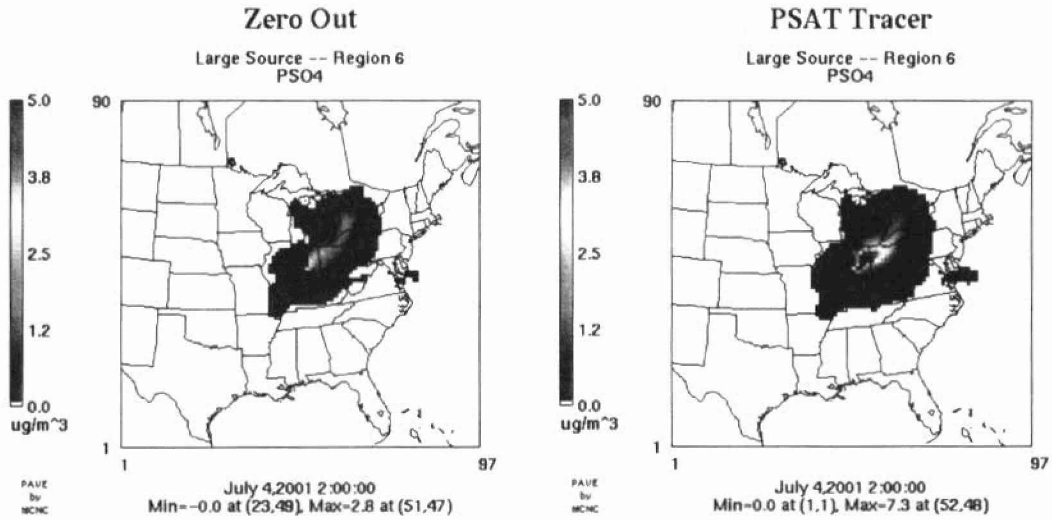
- Ammonia: Reliable estimates of the amount and temporal pattern of ammonia emissions are important in the modeling. Although USEPA has provided little or no information concerning ammonia emissions, we believe that USEPA is using emissions information which may be out-dated (e.g., temporal profiles derived by model-to-monitor comparisons, rather than actual process-level data). We encourage USEPA to use up-to-date methodologies for estimating these emissions.

- Other Sectors: USEPA has stated that its baseline emissions inventory used for its modeling has "some known gaps" (page 4599). Efforts to improve the inventory to correct these problems should be undertaken. In addition, little or no information is provided by USEPA concerning biogenic emissions (e.g., what meteorological data were used, including PAR values) and dust emissions (e.g., how was the transportable fraction of $PM_{2.5}$ estimated). These source categories can produce unrealistically large emission estimates, if not handled properly. Clarification of the methodology used by USEPA for these categories should be provided.

(4) Validity of USEPA's Zero-Out Modeling: USEPA conducted modeling in which it eliminated ("zeroed-out") the anthropogenic SOx and NOx emissions in individual states. USEPA should be aware that we are having our contractor develop a source apportionment methodology for fine particles. To supplement USEPA's zero-out modeling for $PM_{2.5}$, we offer some preliminary source apportionment results. The plots below compare the impact on sulfate levels from an imaginary large SOx source located in the Midwest using the zero-out method and the new source apportionment method. On the first day presented (July 2), the two methods produce very consistent results. On the other day (July 4), however, the source apportionment method indicates substantially greater impact. (Note, our contractor is convinced that this is credible and can be explained by understanding the underlying conditions associated with sulfate production.) Thus, it would appear that the zero-out method is reliable and may, in some cases, even underestimate the impact from large SOx sources on sulfate levels.

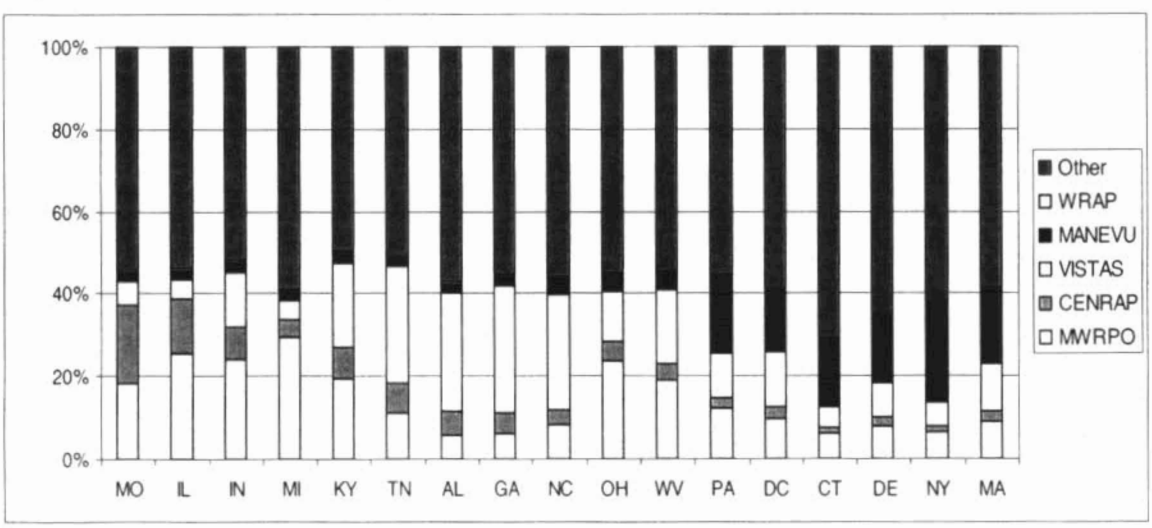


Sulfate concentrations for zero-out (left) analysis v. PSAT (right) analysis for July 2, 2001



Sulfate concentrations for zero-out (left) analysis v. PSAT (right) analysis for July 4, 2001

One other comment on USEPA's zero-out modeling is what we believe it says about transport for $PM_{2.5}$. Based on the results in Appendix H of USEPA's modeling technical support document (and supplemental information provided via e-mail on February 9, 2004), we prepared the following summary of contributions to $PM_{2.5}$ violations. (Note, all nonattainment sites in a given state were averaged together to produce the single values for that state presented here.) The figure indicates that SOx and NOx sources from nearby states (within that Regional Planning Organization) have a large impact on a given urban nonattainment problem, but also that transport from SOx and NOx sources located in more distant states (in other Regional Planning Organizations) is an important factor. (Note, it is our understanding that the difference between the "other" amount shown in the figure represents anthropogenic emissions other than SOx and NOx, and natural emissions.)



Percent contributions to PM *•2.5* ***nonattainment sites***

(5) Potential Applicability to Regional Haze: USEPA has requested public comments on "the extent to which the reductions achieved by these rules would, for States covered by the IAQR, satisfy the first long term strategy for regional haze, which is required to achieve reasonable progress towards the national visibility goal by 2018." USEPA has also requested comment on whether the proposed emissions reductions would satisfy the Best Available Retrofit Technology (BART) requirements under the CAA for the affected EGUs in the affected states.

In response, we wish to note that our modeling analyses (see attached modeling report) show that the proposed emission reductions may be sufficient to meet the reasonable progress goals in many Class I areas located in and impacted by emissions from our States.

With respect to the issue of satisfying the BART requirements, we do not believe that USEPA has provided sufficient information for us to comment. As USEPA knows, the CAA requires consideration of several factors in determining BART, including the costs of compliance, the energy and non-air quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. We do not believe that USEPA has provided this information for the affected sources and, thus, are unable to comment on this issue. It is clear, however, that the BART requirement remains in place for the other 25 BART-eligible source categories and states will be required to conduct the necessary BART analyses for sources in these other (non-EGU) categories.

(6) Adequacy of Proposed Emissions Reductions: It may be premature to comment on the adequacy of the proposed SOx and NOx emissions reductions from EGU sources. The relative amounts of regional and local reductions needed for attainment should be estimated prior to finalizing this rulemaking. This is because once USEPA establishes the federal requirement for emission reductions for certain source categories (i.e., EGUs), some states are prohibited by state statute from imposing more stringent requirements. We agree with USEPA's statement about the need to "set up a reasonable balance of regional and local controls to provide a cost effective and equitable governmental approach to attainment with the NAAQS for fine particles and ozone." (Page 4612)

Furthermore, we believe that this determination is the responsibility of the state governments. (USEPA acknowledges this on page 4585: "the CAA places the responsibility for controls needed for attainment on both upwind States and their sources, and on local sources.") Consequently, we intend to perform initial attainment analyses later this year (or early next year) to estimate what it will take to meet the ambient standards for ozone and $PM_{2.5}$, and the reasonable progress goals for haze. We will share the results of these analyses with USEPA at that time and hope that USEPA will consider them prior to finalizing this rulemaking.

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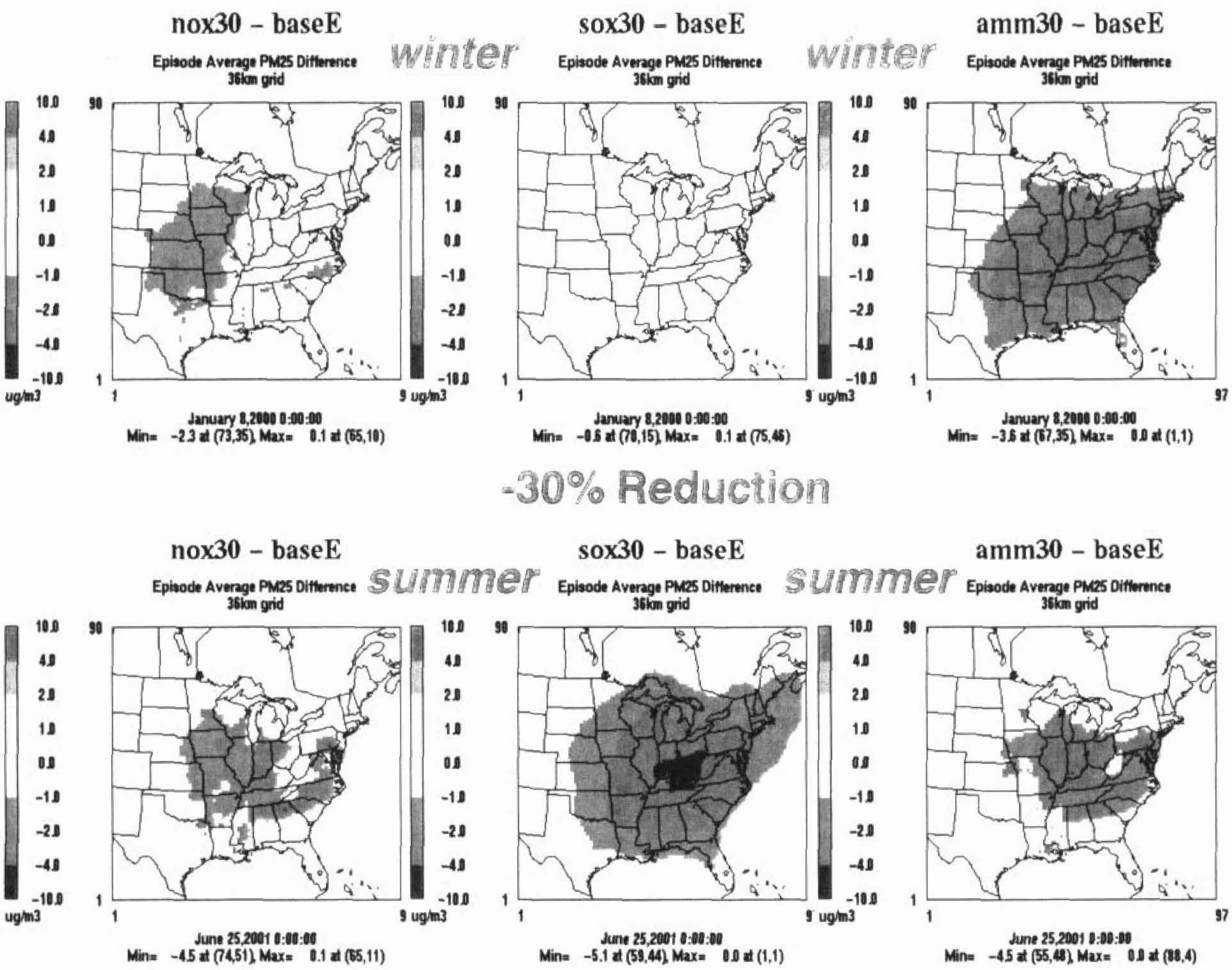
Finally, we believe that USEPA should continue to study and, if appropriate, require regional emission reductions for other pollutants, especially ammonia. (On page 4583, USEPA has requested comment on its decision to not regulate other components of transported $PM_{2.5}$.) Our preliminary model sensitivity analyses (see plots below) indicate that reducing ammonia emissions is effective in reducing $PM_{2.5}$ concentrations on a broad spatial scale, especially during the winter. Independent analyses of air quality data by our contractor also showed ammonia-limited conditions in portions of the upper Midwest, including several urban areas (see "The Effects of Changes in Sulfate, Ammonia, and Nitric Acid on Fine PM Composition at Monitoring Sites in Illinois, Indiana, Michigan, Missouri, Ohio, and Wisconsin, 2000-2002", February 20, 2004, C. Blanchard). In addition, USEPA's source apportionment studies (page 4605) found that back trajectories point to areas with high ammonia emissions in the upper Midwest, suggesting the effects of transport. Furthermore, we believe that a consistent federal approach may be the most effective way to regulate emissions from the major ammonia sources. Thus, we encourage USEPA to look carefully at the need for requiring regional ammonia emission reductions.



Changes in $PM_{2.5}$concentrations associated with a 30% reduction in NOx (left), SOx (middle), and ammonia (right) emissions for winter (top) and summer (bottom) periods

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Lake Michigan Air Director Consortium

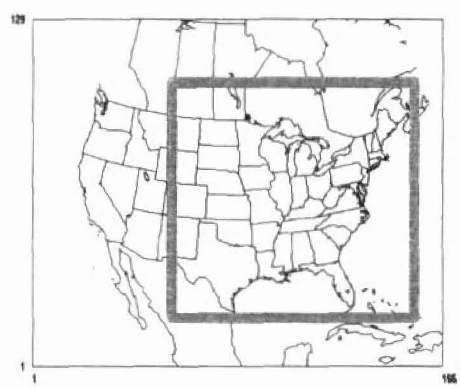
Interstate Air Quality Rule: Modeling Analysis

The purpose of this document is to summarize the modeling performed by the Lake Michigan Air Directors Consortium to assess the air quality benefits of the proposed Interstate Air Quality Rule (69 FR 4566). The key findings of the modeling are as follows:

- The proposed SOx and NOx emission reductions, in combination with expected federal and state controls, will reduce ozone and fine particle concentrations, and improve visibility levels in the eastern U.S. (Note, if "banked" SOx and NOx emissions are accounted for, then the air quality benefit is less than that associated with the proposed emission caps.)
- Although future year design values are estimated to below the ambient standards in many counties, residual ozone and $PM_{2.5}$ nonattainment problems exist in a number of urban areas in the eastern U.S.
- Future year visibility levels are estimated to be on (or below) the "glide path" towards natural conditions in many Class I areas in the eastern U.S.
- The modeling results are qualitatively similar to those reported by USEPA in their Federal Register notice and "Technical Support Document for the Interstate Air Quality Rule, Air Quality Modeling Analysis" (January 2004).

Modeling Overview

The elements of the modeling are as follows:



Model: CAMx

Domain/Grid: Eastern U.S. domain at 36 km (see box in "red" to the right)

Year: 2002 (full year)

Scenarios: 1999base (Base E)

2010base
2010control (IAQR emissions reductions)
2010control-alternative (IAQR reductions w/o "banked" emissions)[1]

2015base
2015control (IAQR emissions reductions)
2015control-alternative (IAQR reductions w/o "banked" emissions)[1]

[1] This scenario reflects the proposed emission caps.

It should be noted that there are several limitations with this analysis, including less than desirable model performance for various $PM_{2.5}$ species (i.e., sulfates, nitrates, and organics), concerns with emission estimation methodologies for several source categories, and use of growth and control factors of unknown quality. As such, the modeling results are not definitive and should only be viewed as qualitative in nature (i.e., approximating the improvement in air quality, but not defining a specific level of [future] air quality). More reliable modeling will be performed over the next couple of years to support SIP development. Nevertheless, some modeling now to assess the air quality benefits of the proposed rule is appropriate both to serve as the basis for making comments on the proposed rule and to help direct initial control strategy work.

Modeling Inventory

LADCO prepared a base year modeling inventory using USEPA's National Emissions Inventory for 1999 (version 2.0), with the following improvements:

Point Sources:	Utility temporal profiles based on analysis of CEM data
Mobile Sources:	Based on MOBILE6
Ammonia:	Monthly and hourly livestock emissions based on new temporal profiles from Rob Pinder; dairy cow emissions based on Rob Pinder's model; monthly fertilizer application emissions derived using a consistent national profile; and eliminated emissions for people and pets (dogs and cats)
Dust:	Emissions reduced to reflect the transportable fraction of fugitive dust
Other:	Updated Canadian emissions inventory (1995 data)
Fires:	Eliminated NEI (and CMU) fire emissions
Biogenics:	Used BIOME3, with updated meteorology and PAR values
Spatial:	Revised/corrected surrogates for other area (including ammonia), nonroad, and mobile sources
Temporal:	Revised/corrected profiles for point, other area, nonroad, and mobile; profile for recreational marine based on Wisconsin data

Documentation for the 1999 Base E inventory is provided at http://www.ladco.org/tech/emis/BaseE/baseEreport.pdf. A cursory comparison of Base E to USEPA's 1996 and 2001 (proxy) inventories showed mixed results (i.e., for some source categories and pollutants, Base E compared better with the 1996 inventory, for others, with the 2001 inventory).

The 2010 and 2015 base inventories were derived by adjusting the 1999 base inventory to reflect expected growth and control. The adjustment factors are based on data supplied by USEPA for 1996[2], 2001[1,3], 2010[1,4], and 2015[3]. The adjustment factors were calculated based on the ratio of 2010 to 2001 and 2015 to 2001 emissions. (Note, in light of the comparisons between the 1999 Base E inventory and USEPA's 1996 and 2001 inventories, use of the 2001 inventory to derive these factors provided a somewhat conservative estimate.)

Adjustment factors were calculated based on the following source, pollutant, and geographic classes:

> Source: EGU (applied to elevated point source file), Non-EGU (applied to low point source file), Area (w/o livestock and w/ livestock), Motor Vehicles, and Non-Road
>
> Pollutant: VOC, NOx, CO, SO2, PM2.5, PM-coarse, and NH3
>
> Geography: state-specific for IL, IN, MI, OH, and WI; and region-specific for CENRAP (north), CENRAP (south), MANEVU, VISTAS, and WRAP

The 2010 and 2015 control inventories were derived by adjusting the 2010 and 2015 base inventories to reflect the additional SOx and NOx reductions from the proposed rule. The adjustment factors were based on data supplied by USEPA. An alternative set of adjustment factors were also derived to reflect strict compliance with the proposed emission caps (i.e., elimination of any banked emissions.)

The table below provides a summary of the future year EGU emissions for all states in the continental U.S. (and the 28 states affected by the proposed rule). The following pages show a graphical summary of SOx, NOx, and VOC emissions and the assumed changes in elevated point source emissions.

EGU Emissions Summary – All States *(28 States)*

		SOx	NOx
2010	Base	9.8M	3.9M
	IAQR	6.1M *(5.4M)*	2.5M *(1.7M)*
	"Caps"	*(3.9M)*	*(1.6M)*
2015	Base	9.2M	4.0M
	IAQR	5.4M *(4.7M)*	2.3M *(1.5M)*
	"Caps"	*(2.7M)*	*(1.3M)*

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[2] See April 18, 2003, e-mail from Ron Ryan, EMAD, OAQPS, USEPA to Mark Janssen, LADCO

[3] See May 20, 2003, e-mail from Phil Lorang, EMAD, OAQPS, USEPA to Amy Royden, STAPPA/ALAPCO

[4] See January 14, 2004, e-mail from Ron Ryan, EMAD, OAQPS, USEPA to Mark Janssen, LADCO

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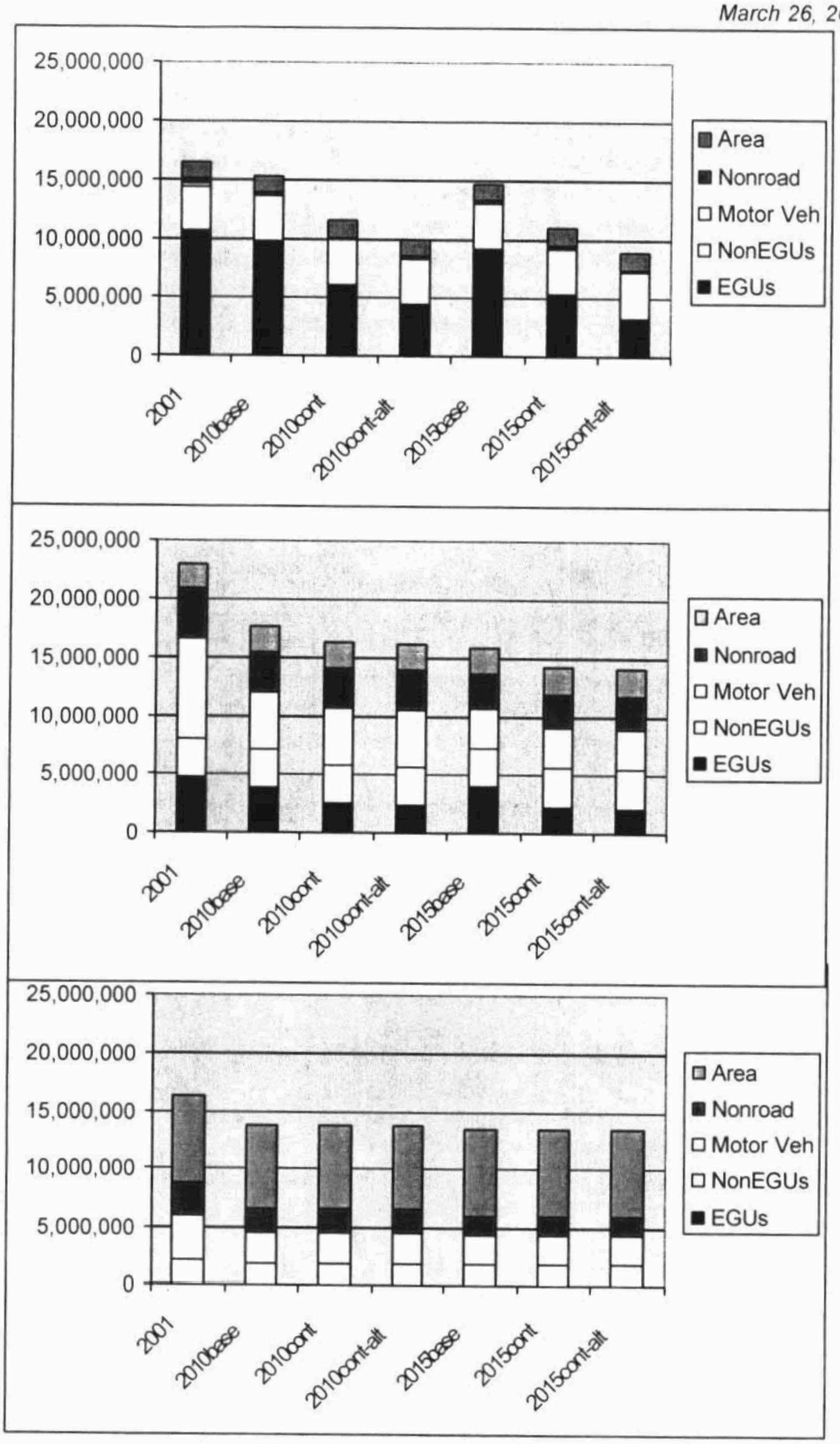

Domainwide annual SOX (top), NOx (middle), and VOC (bottom) emissions

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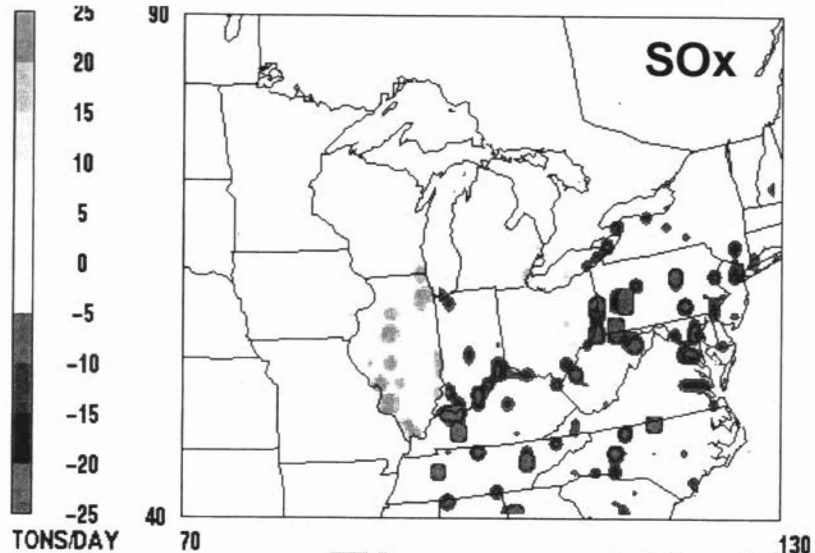
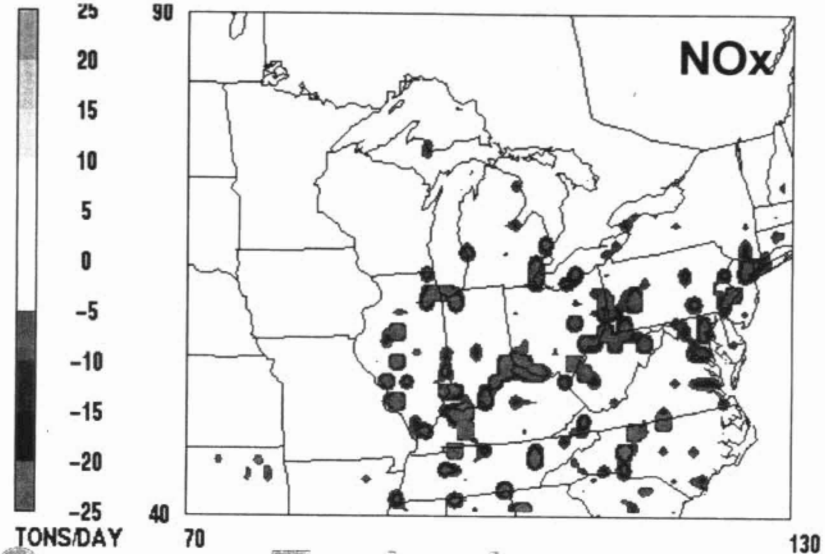
Elevated Point Source Emissions

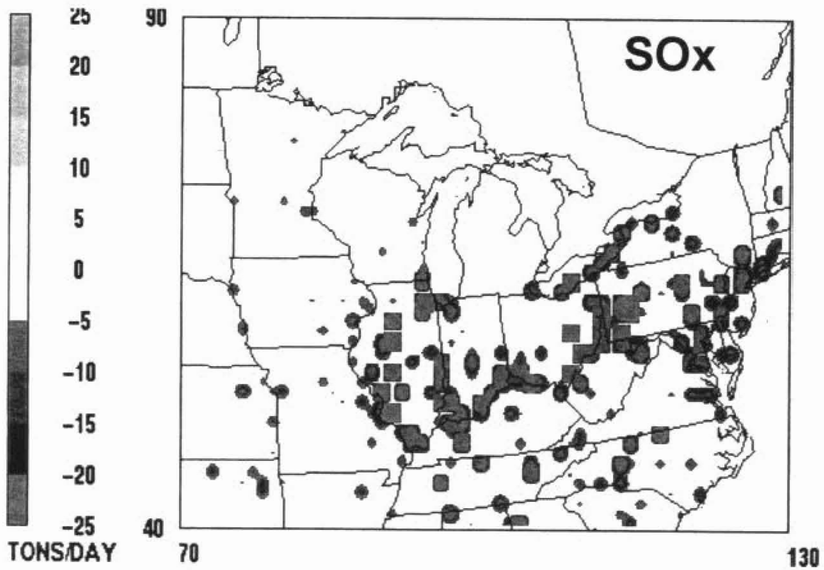
2010base – base(1999)



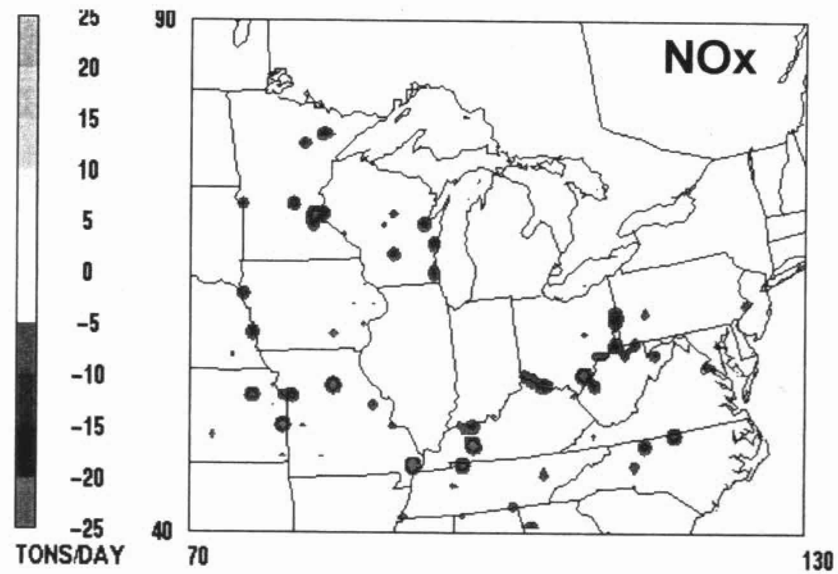
2010base – base(1999)



2010IAQR – 2010base



2010IAQR – 2010base



Ozone Modeling Results

Future year design values were calculated in accordance with USEPA's modeling guidance ("Draft Guidance on the Use of Models and Other Analyses in Attainment Demonstrations for the 8-Hour Ozone NAAQS", EPA-454/R-99-004, May 1999). The observed (base year) design values were based on 2000-2002 air quality data, consistent with USEPA's modeling analysis.

Maps of the design values are presented on the following page for the base case (2000-2002 observed data), 2010base, 2010IAQR, and 2010IAQR without banking. In addition, the number of "nonattainment" counties (i.e., design value estimated to be above the standard) are as follows:

State	Base Year	2010base EPA/LADCO	2010IAQR EPA/LADCO	2015base EPA/LADCO	2015IAQR EPA/LADCO
IL	3	0/1	0/1 (1)*	1/1	0/1 (1)*
IN	19	1/3	1/2 (2)*	1/2	1/2 (1)*
MI	13	0/1	0/1 (0)*	1/1	0/0 (0)*
OH	28	2/5	1/4 (4)*	1/4	0/3 (0)*
WI	8	3/5	3/5 (5)*	2/5	1/4 (2)*

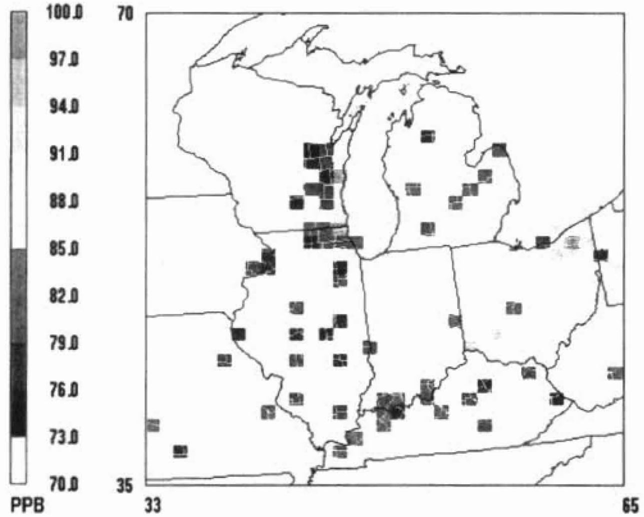
** = without banked emissions*

Additional analyses were performed to assess the effect of: (1) estimating future year design values using a single high ozone episode (i.e., late June 2002), (2) using 12 km grid resolution, and (3) using plant-specific emissions projections (based on the IPM model). Using the same metric as above (i.e., number of nonattainment counties), the results below indicate only a slight difference using episode data (compared to the full summer) and using 12km data (compared to the 36 km data).

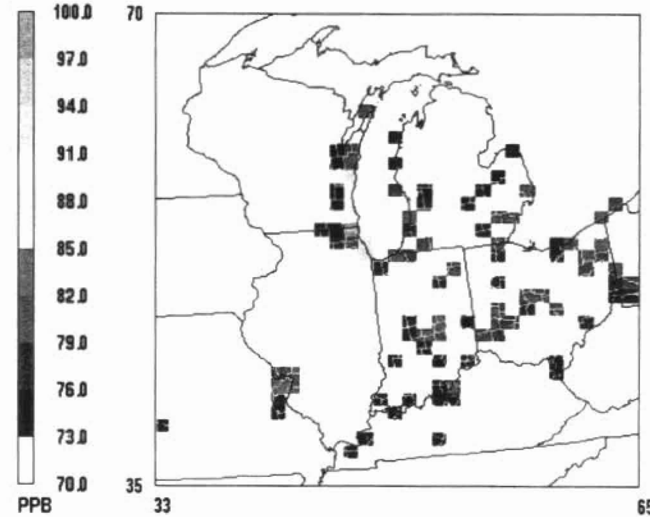
State	Base Year	2010base			2010IAQR		
		Summer36	June36	June12	Summer36	June36	June12
IL	3	1	1	2	1	1	2
IN	19	3	3	3	2	2	3
MI	13	1	3	1	1	3	1
OH	28	5	5	8	4	4	5
WI	8	5	5	6	5	5	5

O_3

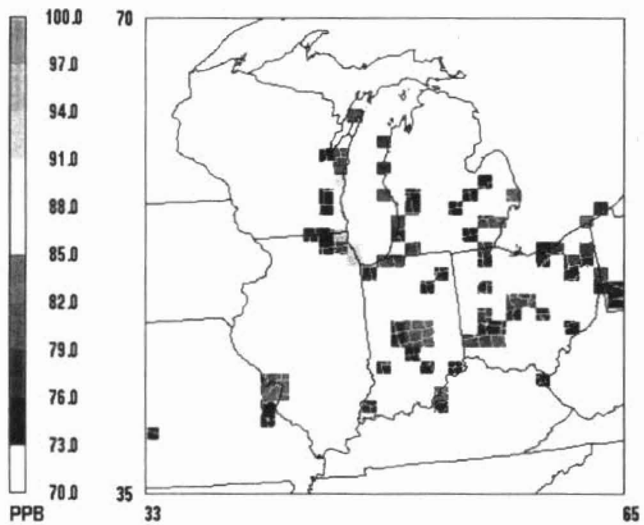
Base (2000-2002)



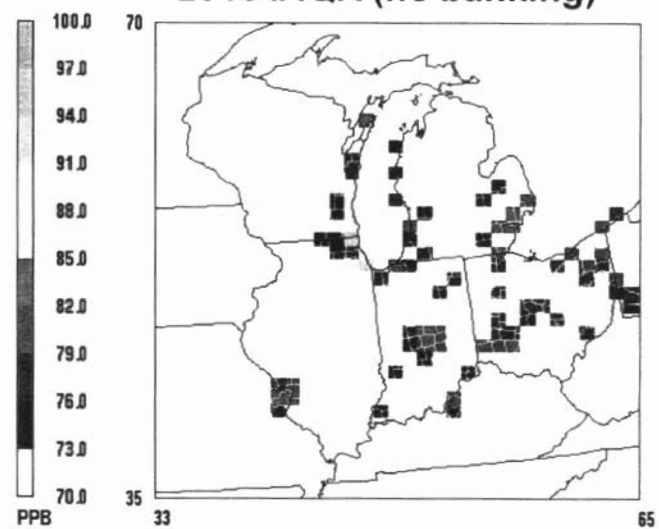
2010 Base



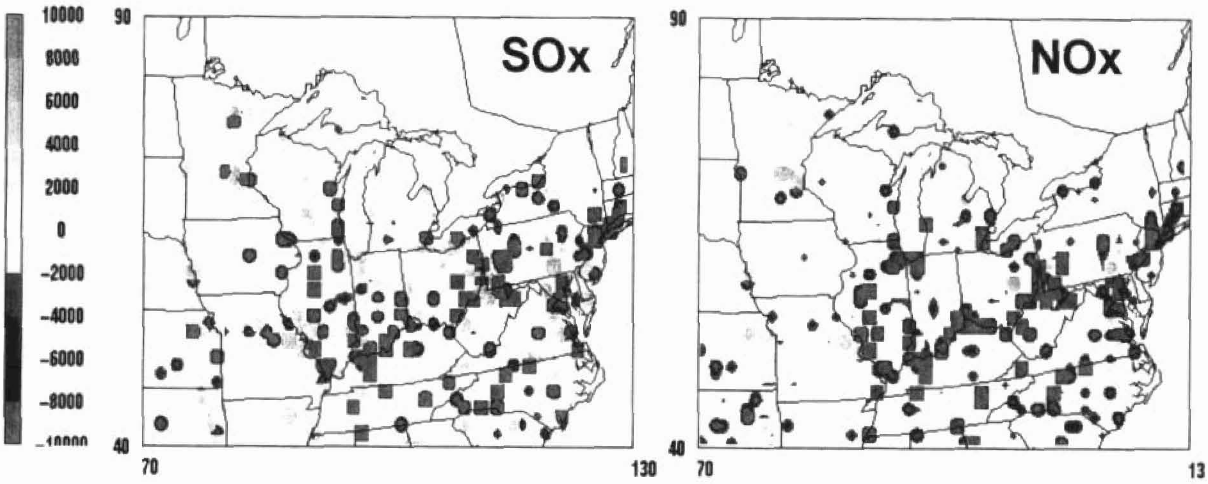
2010 IAQR



2010 IAQR (no banking)



The differences in elevated point source SOx and NOx emissions with IPM plant-specific data are shown in the figures below. (Note, in addition to the obvious spatial differences in emissions, the amount of emissions in the IPM plant-specific data files are lower. The reason for the lower emissions is not clear.)



The results with the IPM plant-specific data show generally lower future year design values for ozone, as might be expected with lower emission levels:

State	County	2010base Summer36	2010base IPM(Summer36)	2010IAQR Summer36	2010IAQR IPM(Summer36)
IL	Cook	92.7	90.8	91.7	90.2
IN	Hamilton	85.5	85.0	----	----
	Lake	96.9	94.9	95.9	94.3
	Porter	88.6	87.6	87.8	87.0
MI	Macomb	86.4	85.6	85.6	85.0
OH	Clinton	86.0	84.4	----	----
	Geauga	90.5	90.4	89.3	89.6
	Lake	88.8	88.3	87.8	87.6
	Lucas	87.2	86.6	86.5	86.1
	Summit	88.8	89.0	87.5	88.2
WI	Kenosha	97.5	96.9	96.5	96.2
	Milwaukee	88.6	88.0	87.6	87.3
	Ozaukee	88.3	87.6	87.1	86.8
	Racine	89.3	88.7	88.3	88.0
	Sheboygan	92.8	91.6	91.4	90.7

In summary, the modeling results show considerable improvement in future year design values, but there are residual ozone nonattainment problems. These results are similar to those reported by USEPA.

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$PM_{2.5}$ Modeling Results

Future year design values were calculated in accordance with USEPA's modeling guidance ("Guidance for Demonstrating Attainment of Air Quality Goals for $PM_{2.5}$ and Regional Haze", draft 2.1, January 2, 2001). The observed (base year) design values were based on 2000-2002 air quality data, consistent with USEPA's modeling analysis.

Maps of the base year and future year design values are presented on the following pages for the base case (2000-2002 observed data), 2010base, 2010IAQR, and 2010IAQR without banking; and the base case (2000-2002 observed data), 2015base, 2015IAQR, and 2015IAQR without banking. In addition, the number of "nonattainment" counties (i.e., design value estimated to be above the standard) are as follows:

State	Base Year	2010base EPA/LADCO	2010IAQR EPA/LADCO	2015base EPA/LADCO	2015IAQR EPA/LADCO
IL	5	4/5	0/2 (2)*	3/4	1/2 (2)*
IN	10	2/3	0/2 (2)*	2/2	0/2 (1)*
MI	3	1/3	1/1 (1)*	1/2	1/1 (1)*
OH	13	11/9	5/2 (1)*	8/8	4/1 (0)*
WI	0	0/0	0/0 (0)*	0/0	0/0

** = without banked emissions*

Stacked bar charts are presented (on the page following the design value maps) showing the chemical speciation of the $PM_{2.5}$ concentrations in urban areas in the region. The charts show reductions in future year sulfate levels, but relatively little change in future year organic carbon and nitrate levels.

Additional analyses were performed to assess the effect of using plant-specific emissions projections (based on the IPM model). The results with the IPM plant-specific data show generally lower future year design values for $PM_{2.5}$, as might be expected with lower emission levels:

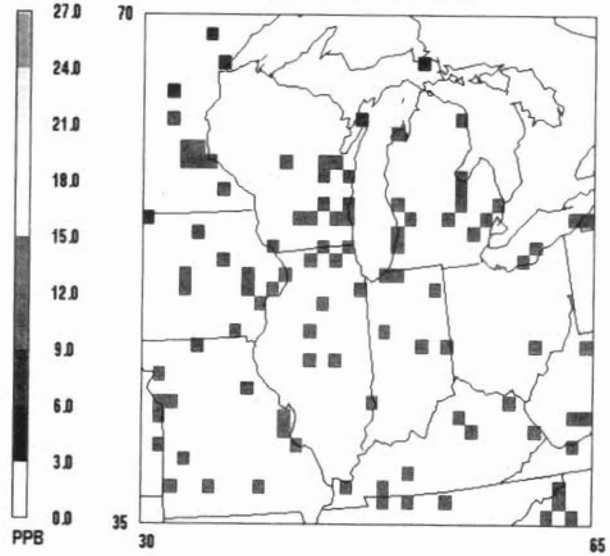
		2010base		2010IAQR	
State	County	Summer36	IPM(Summer36)	Summer36	IPM(Summer36)
IL	Cook	19.6	17.9	18.0	16.9
	DuPage	15.3	14.0	----	----
	Madison	19.5	18.0	17.9	16.7
	St. Clair	16.0	14.8	----	----
	Will	15.5	14.0	----	----
IN	Elkhart	15.4	14.3	----	----
	Lake	17.7	16.1	16.4	15.2
	Marion	17.5	16.4	16.0	15.1
MI	Kalamazoo	15.0	13.9	----	----
	Oakland	15.6	14.9	----	----
	Wayne	19.8	19.0	18.4	17.9

OH	Butler	15.0	14.2	----	----
	Cuyahoga	17.8	17.4	16.4	16.0
	Franklin	16.0	15.2	----	----
	Hamilton	16.4	15.5	----	----
	Jefferson	15.9	15.5	----	----
	Montgomery	17.1	16.2	15.2	14.4
	Scioto	15.7	15.0	----	----
	Stark	16.6	15.8	----	----
	Summit	15.5	14.8	----	----

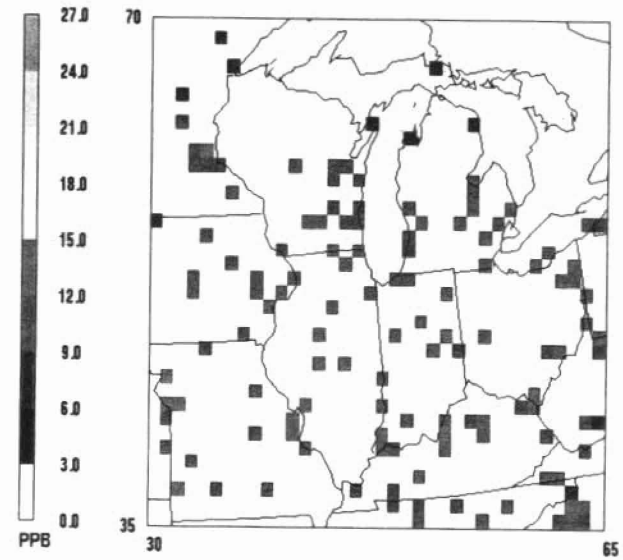
In conclusion, the modeling results show considerable improvement in future year design values, but there are residual $PM_{2.5}$ nonattainment problems. These results are similar to those reported by USEPA.

$PM_{2.5}$

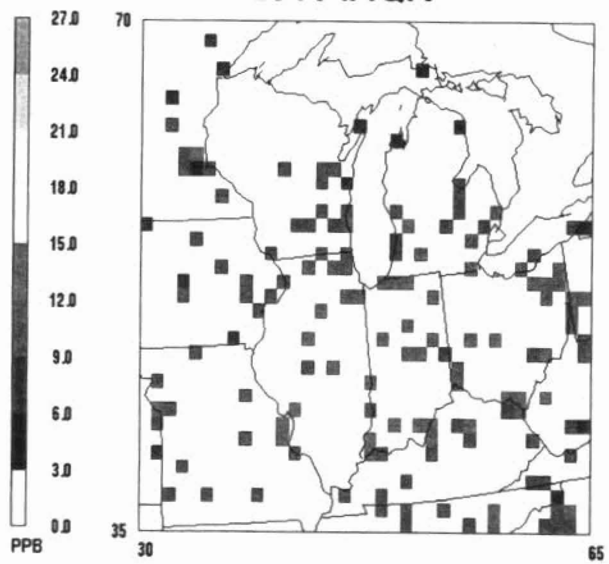
Base (2000-2002)



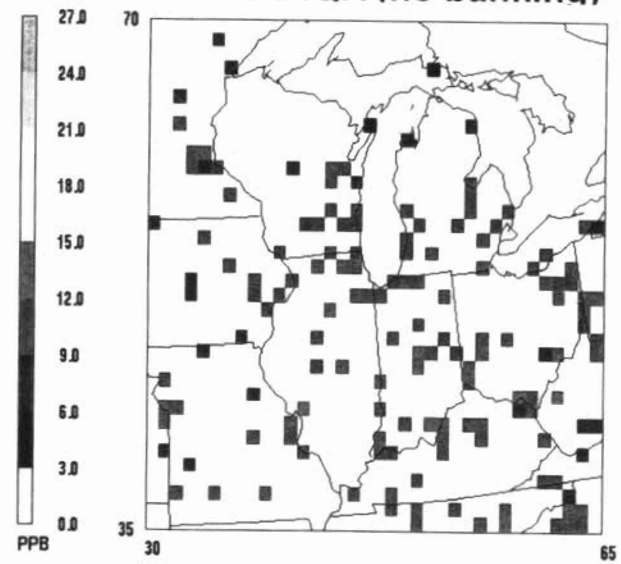
2010 Base



2010 IAQR

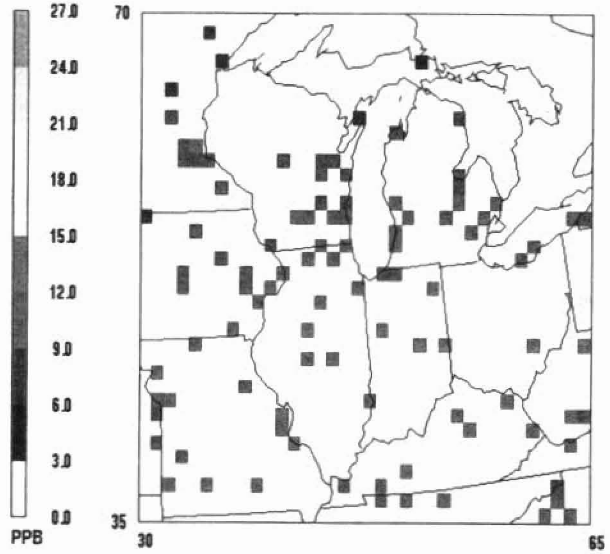


2010 IAQR (no banking)

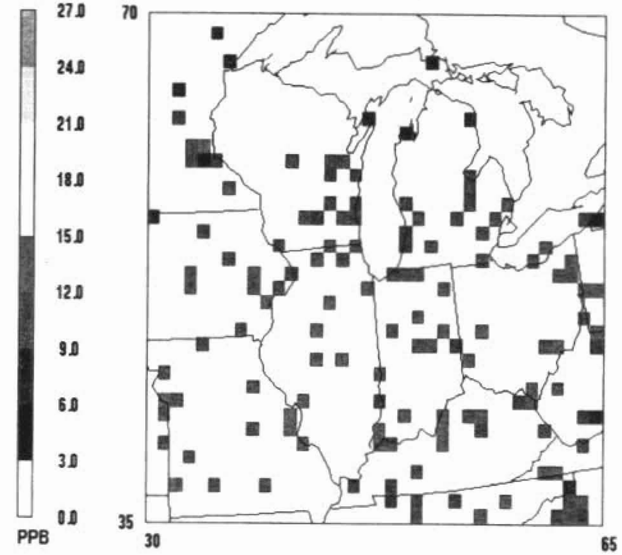


$PM_{2.5}$

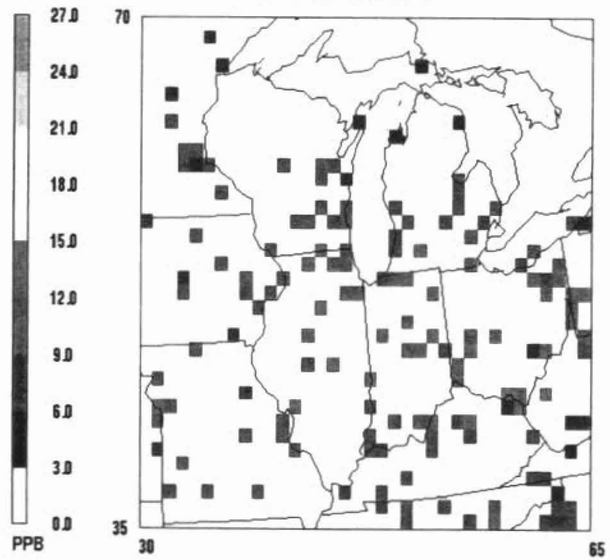
Base (2000-2002)



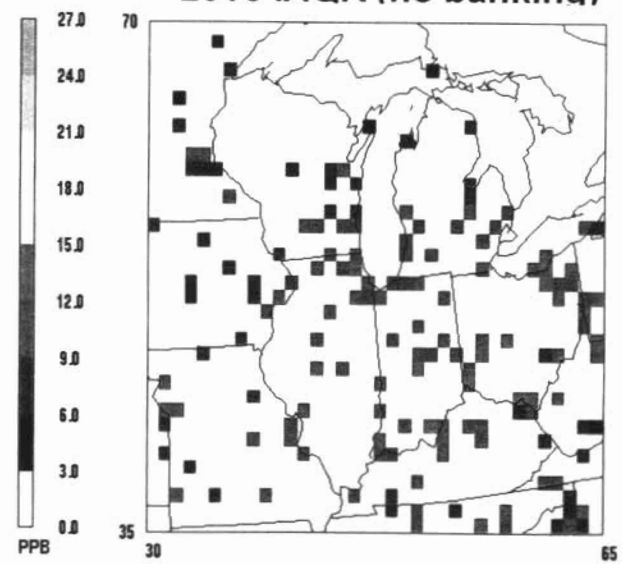
2015 Base



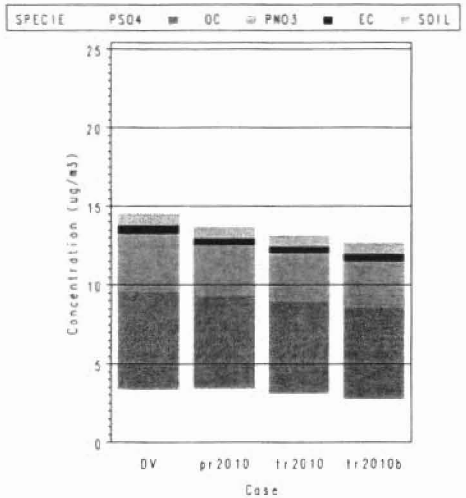
2015 IAQR



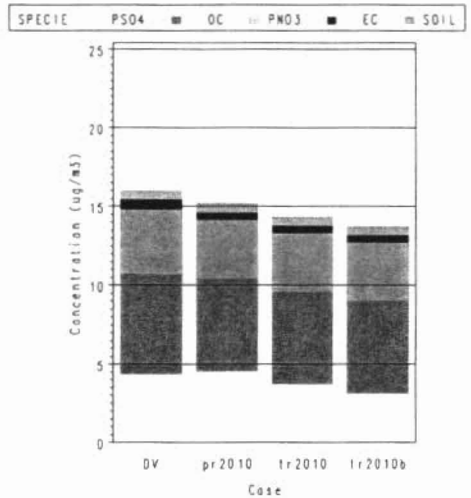
2015 IAQR (no banking)



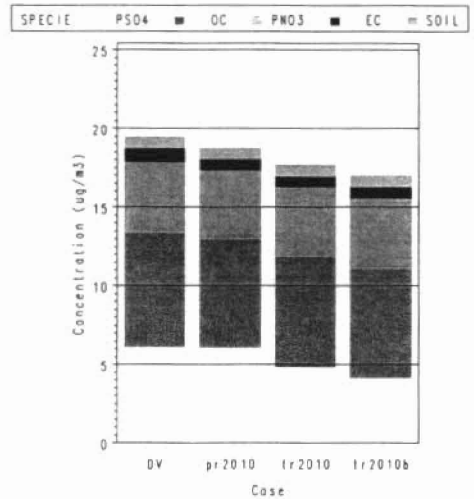
Minneapolis



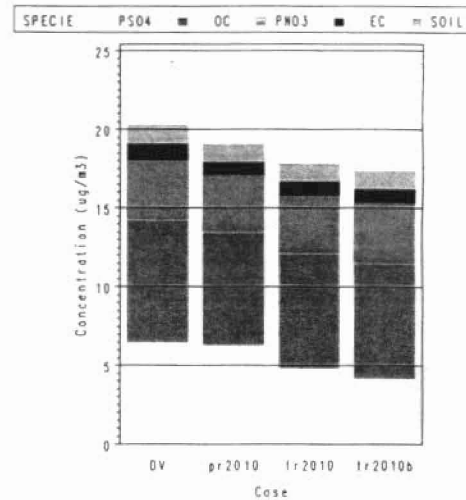
Milwaukee



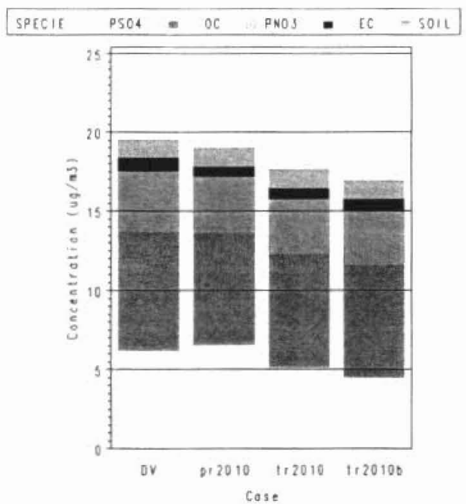
Detroit



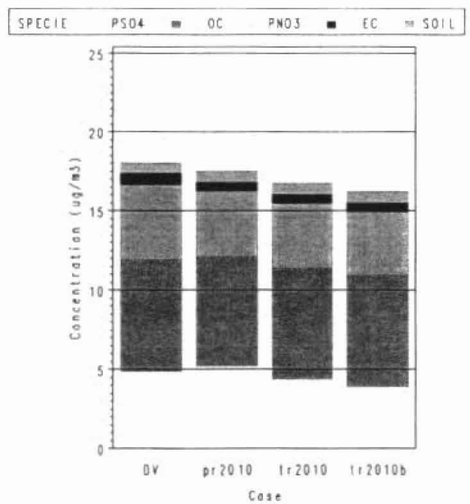
Cleveland



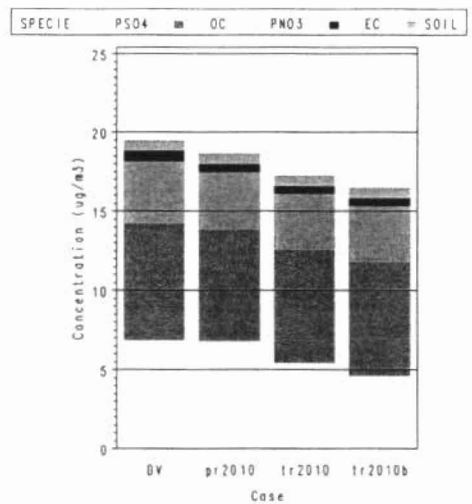
St. Louis



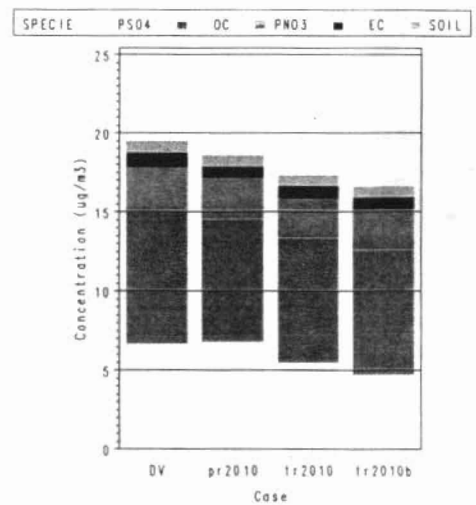
Chicago



Indianapolis

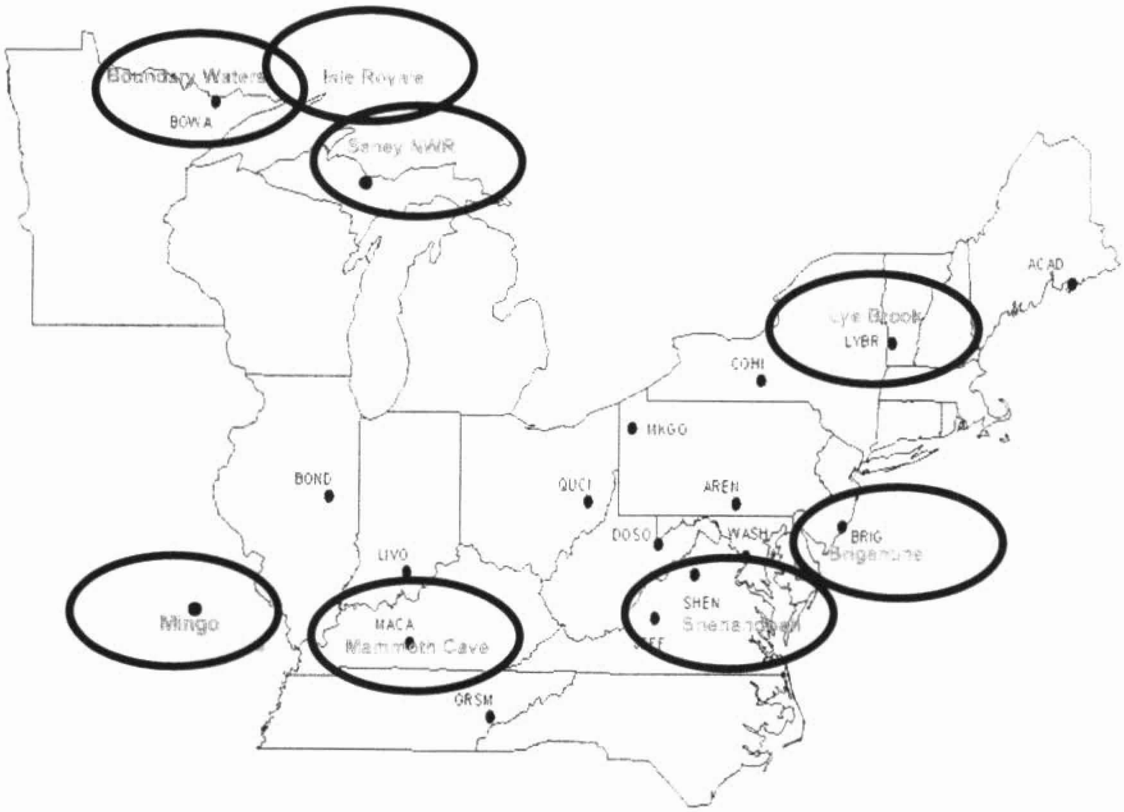


Cincinnati



Visibility Modeling Results

Future year visibility levels were calculated in accordance with USEPA's modeling guidance ("Guidance for Demonstrating Attainment of Air Quality Goals for $PM_{2.5}$ and Regional Haze", draft 2.1, January 2, 2001). The observed (base year) visibility levels were based on 2002 air quality data. The modeling results are presented here for eight nearby Class I areas:



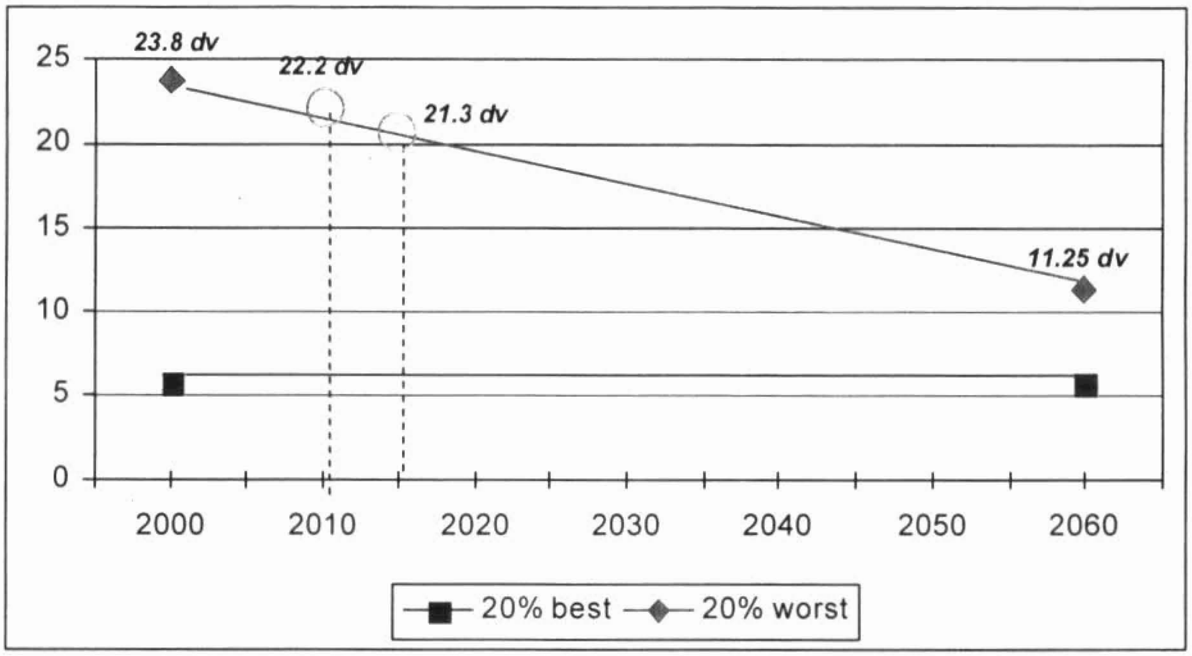
A table of visibility levels is provided on the following page for the baseline (estimated using 2002 air quality data), 2010, 2015, and "natural" conditions. (The default values in "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule", EPA-454/B-03-005, September 2003, were used to represent natural conditions.) Also provided is a graphical depiction of the future visibility levels for Shenandoah National Park and Seney National Wildlife Refuge. As can be seen, future year visibility levels are estimated to be on (or below) the "glide path" towards natural conditions.

March 26, 2004

Visibility Metric (deciviews)

	Isle Royale	Seney	BOWA	MACA	Mingo	Shenandoah	Brigantine	Lye Brook
Baseline (2002)	21.41	23.77	20.67	28.05	28.08	28.90	28.30	23.23
2010base	21.13	23.34	20.52	27.22	27.35	27.19	26.74	21.92
2010base-IPM	19.82	22.32	19.36	25.87	25.25	25.79	26.27	21.40
2010IAQR	19.90	22.17	19.23	25.80	25.08	24.59	25.26	20.84
2010IAQR-IPM	18.96	21.41	18.49	24.80	23.76	23.48	24.58	20.29
2010IAQR (w/o bank.)	18.67	21.15	18.14	24.83	23.67	23.44	24.70	20.83
2010"Glide Path Goal"	*20.09*	*22.17*	*19.46*	*25.92*	[illegible]	*26.62*	*26.10*	*21.68*
2015base	20.22	22.62	19.68	26.55	26.39	26.21	26.40	21.73
2015IAQR	18.92	21.28	18.37	24.60	23.70	23.01	24.02	20.16
2015IAQR (w/o bank.)	17.02	19.69	16.52	23.21	21.54	21.19	22.83	19.43
2015"Glide Path Goal"	*19.27*	*21.17*	*18.71*	*24.58*	[illegible]	[illegible]	*24.73*	*20.72*
2018 "Glide Path Goal"	*18.45*	*20.17*	*17.95*	*23.25*	[illegible]	*23.77*	*23.36*	*19.75*
2064"Goal" (natural conditions)	*11.22*	*11.37*	*11.31*	*11.53*	*11.27*	*11.25*	*11.28*	*11.25*

Seney National Wildlife Refuge



Shenandoah National Park