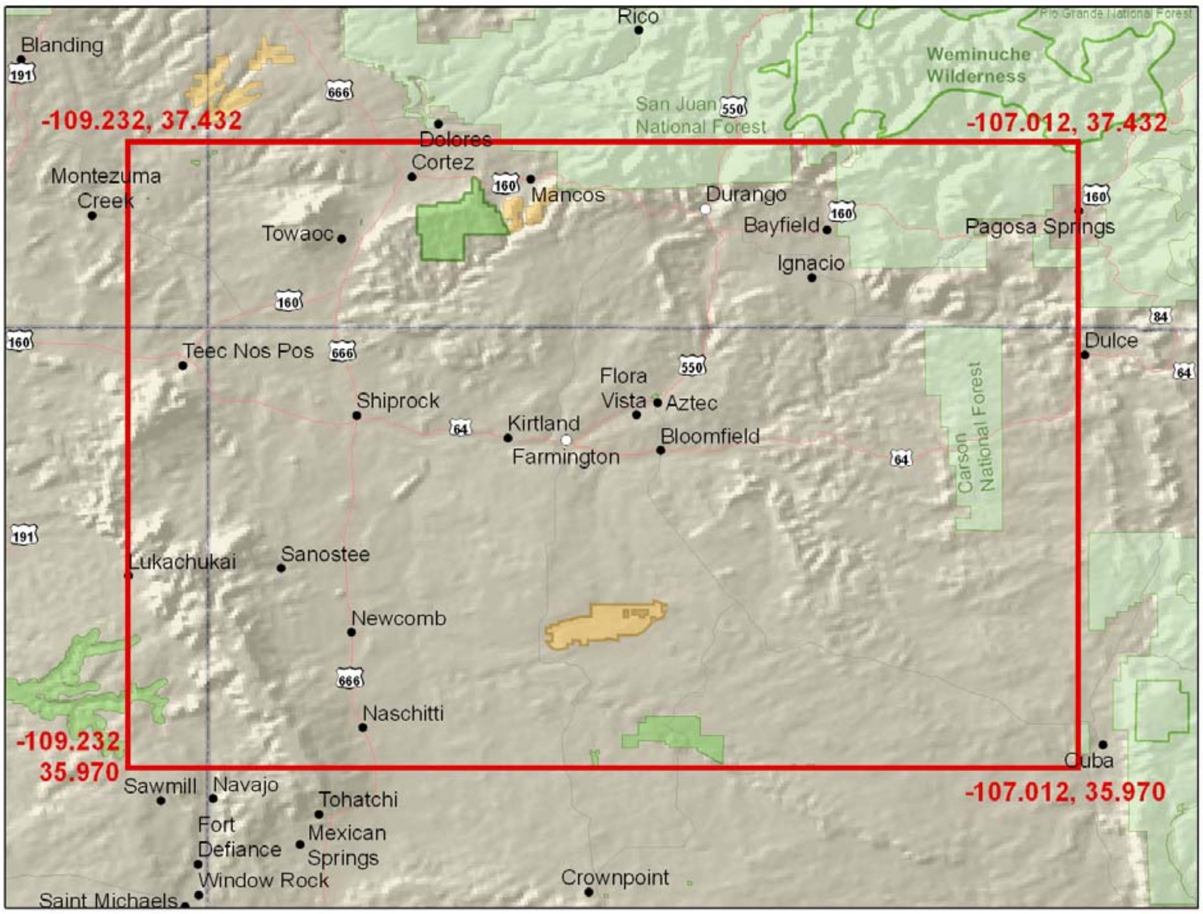
POWER PLANTS SECTION

Four Corners Air Quality Task Force
Report of Mitigation Options



November 1, 2007

The report is a compilation of mitigation options drafted by members of the Four Corners Air Quality Task Force. This is not a document to be endorsed by the agencies involved, but rather, a compendium of options for consideration following completion of the Task Force's work in November 2007.

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Power Plants: Preface

Overview

The Power Plants Work Group was charged with developing mitigation strategies for existing, proposed, and future power plants in the Four Corners area. For each strategy, one or more work group members provided a basic description of the strategy, ideas for implementation, and discussed feasibility issues to the extent possible.

Participation in the Power Plants Work Group included representatives from state, tribal and federal agencies; industry (including regional power plants); citizens; and interest groups. Ten to 20 participants attended each face-to-face meeting throughout the process. In total, the Power Plant Work Group brainstormed a total of 36 mitigation options and drafted 34. In addition, work group members helped in drafting 18 mitigation options for the Energy Efficiency, Renewable Energy and Conservation section.

Organization

The Power Plants work group initially collected information on existing emissions inventories and emissions projections for existing and proposed power plants. A spreadsheet, called Four Corners Area Power Plants Facility Data Table**,** is located at the end of the Power Plants section and was used as a tool to help supplement mitigation options papers with emissions reduction estimates. The work group divided the remainder of its work into the following categories.

Existing Power Plants: The work group first considered existing power plants, focusing on the two largest power plants in San Juan County: San Juan Generating Station (1800 MW) and Four Corners Power Plant (2000 MW). Eleven mitigation options were brainstormed and drafted for this section. The options drafted ranged from software applications and process optimization to retrofitting NOx and SO_2 emissions control technologies.

Proposed Power Plants: The work group next considered the proposed power plants category. The focus here was on the proposed Desert Rock Energy Project, a 1500 MW coal-fired power plant to be built in Burnham, 30 miles Southwest of Farmington. Options included funding of air quality improvement initiatives and consideration of the Integrated Gasification Combined Cycle (IGCC) process. Four of the 11 comments received on the Power Plants section of the Task Force Report during the public comment process were against building another power plant in the Four Corners area. Desert Rock also submitted comments on the Task Force report. Please see all the public comments pertaining to power plants in an appendix at the end of this section.

Future Power Plants: The work group discussed and documented eight strategies that future power plants could use to mitigate air pollution, including a carbon capture and sequestration (CCS) option, an option for clean coal incentives, large scale renewable energy production, and also an option on nuclear energy production.

Overarching Issues: Finally, the Power Plants report section also has an overarching category for options and ideas that may apply more broadly. Ten options were brainstormed and drafted here, and include mercury pollution mitigation and the Clean Air Mercury Rule (CAMR), cap and trade programs, greenhouse gas mitigation and one calling for a health study.

EXISTING POWER PLANTS: ADVANCED SOFTWARE APPLICATIONS

Mitigation Option: Lowering Air Emissions by Advanced Software Applications: Neural Net

I. Description of the mitigation option

There are many areas of power plant operation where Advanced Software Applications could lower air emissions from current levels. These processes range from the primary power generation equipment, to the various air pollution control devices (APCDs), such as scrubbers, precipitators, baghouses, and SCR units. The best gains in emission reduction couple state-of-the-art APCDs with advanced software applications operating within or in concert with the Distributed Control System, DCS. This mitigation option discusses Neural Network software to lower NO_x emissions at coal combustion low-NO_x burners. Other examples may be found in the Appendix.

Many power plant processes/devices, such as fan speeds, air damper positions, air and coal flows, are automatically controlled by the DCS. The DCS is a networked computer system with “distributed” input/output electronic hardware near the plant control devices, and “live” displays for the control room operators. Given the current state (on/off status or analog value) of every device tag in its database, the DCS uses feedback control algorithms to drive many controlled device variables. Set-points are optimized for the current desired mode of plant operation, such as satisfying a specified megawatt demand at the best possible heat rate.

Neural Networks offer advanced software control by “training” the software to “know” where outputs should be in relation to many inputs. Unlike traditional mathematical equation models, neural networks do not demand intimate understanding of the process. A neural network, sometimes referred to as “fuzzy logic,” is a type of “artificial intelligence” statistical computer program, which classifies large and complex data sets by grouping cases together in a manner similar to the human brain. Neural networks “learn” complex processes by analyzing their performance data.

San Juan Generation Station (SJGS) is currently working with a predictive neural network on Units 1 and 2 to lower NO_x emissions. This advanced software application, provided by the DCS vendor, minimizes NO_x formation by optimizing air flow to the burners (e.g., optimal flame temperature). SJGS is gaining experience with this type of software, anticipating the installation of state-of-the-art low-NO_x burner hardware. When these burners are installed on all units, increased reductions in NO_x are anticipated. Neural network software results in lower NO_x emissions than if the burners were controlled by standard DCS software alone.

The neural network uses inputs from the NO_x and O_2 CEMS, Carbon Monoxide (CO) emissions, burner air, secondary combustion air, coal flow, flame temperature, fan speeds, damper positions, etc. There could be dozens of inputs. The network is trained to identify the relative contribution of each process input to NO_x formation as measured by the CEMS. The network is trained across varying modes of plant operation – full load, partial load, startup, etc. at the lowest possible NO_x emissions. Then, as the generating unit operates in various modes, the neural network predictions refine the control actions the DCS would take on its own. This refinement lowered NO_x emissions by approximately 25% at an Entergy coal fired plant (Intech, July 2006 – “Netting a Model Predictive Combo”).
Note: CO_2 readings do not correlate significantly to NO_x control. Inputs from the NO_x, CO, and O_2 CEMS are used.

Benefits: NO_x reductions of 10% – 30%. Earn NOx Trading Credits as future regulations may require. Another important benefit is that tighter process controls from the neural network may improve the plant heat rate. When the heat rate improves, less energy is needed to maintain required MW load. With less associated stack gas volume for that load, all pollutant emissions decrease.

Trade-offs: Neural network cannot adapt to unforeseen upsets for which it was not originally trained. Neural net refinement control may have to be removed in these situations.

Some existing boiler controls may need to be automated so the neural network can act on them via the DCS. There are significant associated hardware, software, and labor costs. In combustion control schemes, optimizing NO_x for lowest emissions generally increases CO. CO emissions might increase because the neural network allows CO to ride very close to its regulatory limit. Without the network, CO is manually controlled to a lower level providing a cushion for upsets.

Software is processor-intensive.

Burdens: Cost of software application, more powerful computer hardware, "training" labor. Cost of upgrading some of the other controls on the boiler. The neural net is not much good unless it can actually adjust the equipment such as dampers, burner air registers, fan speed, etc. The controls have to be automated and have to be compatible with the neural net.

II. Description of how to implement

A. Mandatory or voluntary:

This option is being considered by San Juan Generating Station as part of consent decree to reduce NO_x emissions. It may be a viable option for FCPP. There may be some grants available to help fund such upgrades to existing power plants in Four Corners area.

FCPP has also installed neural networks and is gaining experience with process and emissions optimization. Desert Rock's potential use of this option is unknown.

B. Indicate the most appropriate agency(ies) to implement:

Federal, State, Tribal regulations should not specify specific control strategies, but rather impose emission limits reasonable for modern control strategies. Grandfathering of plants under NSR for installing enhanced controls, is another debate. However, if Federal NO_x budget trading is extended to this area under a Clear Skies option, the economic incentive of expensive NO_x trading credits to either buy or sell would encourage the final emissions control step of "advanced software applications" to realize optimum economic and environmental benefits.

Differing Opinion: Using NOx Budget trading and other grand fathering strategies do not address the pollution problems associated with old, out of date coal fired power plants. The Four Corners Power Plant is the top emitter of NOx in the Nation. Two coal fired power plants with high levels of emissions are located in the Four Corners. Grand fathering should not be an option. Extensive emissions clean up and control is necessary.

III. Feasibility of the option

A. Technical: Neural network technology is a viable control approach well established in many industrial process settings, but requires intensive computational capability. Powerful, cost-effective computers of recent years have facilitated growth of this technology. Due to some limitations to this control strategy, it takes its place with other advanced control strategies, such as Model Predictive Control.

B. Environmental: Environmental impacts are incidental, such as increased power consumption for more powerful computer hardware.

The point of this option is more efficient operation and thus lower emissions.

C. Economic: Software costs and labor are reasonable in light of the long term emission reductions attained. Generally, software costs are much less than capital expenditures for physical APCDs.

The Monitoring Work group asked if additional CEM or other technology be required to operate as part of the neural net feedback loop. SJGS and FCPP have existing NO_x CEMS to meet state and federal Acid Rain Program monitoring requirements. Acid Rain requires a high level of data quality assurance, including daily calibrations. A neural network continues to function upon loss of one or more inputs, within statistical limits. NO_x minimization control would continue during occasional loss of the NO_x CEMS input.

IV. Background data and assumptions used:
ISA Intech article
Information from San Juan Generating Station
There are many other sources of relevant information, including AWMA, Argonne, DOE.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups
Advanced Software Applications, including neural network control technology, could apply to sources in the Oil and Gas sector

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EXISTING: BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

Mitigation Option: Control Technology Options for Four Corners Power Plant

I. Description of the mitigation option

Summary of Option

Presumptive Best Available Retrofit Technology (BART) emission limits for SO_2 should be applied to all units at Four Corners Power Plant (FCPP). Presumptive BART emission limits for NO_x should be applied to Units 1, 2 and 3; and combustion controls and Selective Catalytic Reduction (SCR) on Units 4 and 5. When BART for PM10 at FCPP is analyzed, the regulatory authority and the facility should consider the control level achieved at San Juan Generating Station.

Background: Best Available Retrofit Technology (BART)

The Four Corners Power Plant consists of five pulverized coal fired boilers. Each boiler was built between 1962 and 1977 and emits more that 250 tons per year of visibility-impairing pollution. The units are therefore subject to the Best Available Retrofit Technology (BART) requirements under the Regional Haze Rule. The BART requirements mandate industrial facilities that cause or contribute to regional haze to control emissions of visibility-impairing pollutants. The Clean Air Act (CAA) states that BART guidelines shall apply to fossil-fueled fired generating power plants with a capacity greater than 750 MW (§169A(b)). The CAA does not exempt individual units of any size from BART requirements.

For Electric Generating Units with a capacity greater than 200 MW, the Environmental Protection Agency (EPA) has provided (rebuttable) presumptive emission limits for sulfur dioxide (SO_2) and nitrogen oxides (NO_x), based on boiler size, coal type and controls already in place. EPA "analysis indicates that these controls are likely to be among the most cost-effective controls available for any source subject to BART, and that they are likely to result in a significant degree of visibility improvement." (70 FR 39131, July 6, 2005). Because the two smaller units (#1 & #2, each at 190 gross MW) are subject to BART and are close in capacity to EPA's 200 MW threshold, the rationale for applying presumptive limits should hold for those units as well. Those presumptive limits (which are 30-day rolling averages) are:

- Unit #1 is 190 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #2 is 190 gross MW dry bottom wall -fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #3 is 253 gross MW dry bottom wall -fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #4 is 818 gross MW cell-burner: 0.15 lb SO_2/mmBtu and 0.45 lb NO_x/mmBtu
- Unit #5 is 818 gross MW cell-burner: 0.15 lb SO_2/mmBtu and 0.45 lb NO_x/mmBtu

Background: FCPP Emissions

In the 1980s, Arizona Public Service (APS) installed venturi scrubbers on Units 1-3, and early generation spray tower scrubbers—but with significant stack gas bypass—on Units 4 and 5. In 2003, APS began a program to further reduce SO_2 emissions at FCPP by eliminating most stack gas bypass. APS succeeded in bringing emissions down from a 30-day rolling plant wide average of 0.44 lb/mmBtu in 2003 to 0.16 lb/mmBtu by 2005, with further improvement to 0.14 lb/mmBtu; this represents a removal efficiency of 92 percent. Although NO_x and PM_{10} emissions were not addressed in that effort, NO_x emissions have been reduced slightly, but FCPP is still the largest emitter of NO_x among coal-fired power plants nationwide.[1] The current rate at which FCPP emits NO_x is approximately 0.54 lb/mmBtu.

The FCPP is located on the Navajo Reservation, and was previously regulated by emission limitations set by the State of New Mexico. The Tribal Authority Rule, however, generally stated that state air quality regulations could not be enforced against facilities on the Indian reservation. EPA, therefore, has to issue federally enforceable emission limitations for FCPP. On August 31, 2006 EPA Region 9 proposed a Federal Implementation Plan (FIP) to establish federally enforceable emission limits for SO_2, NO_x, total PM, and opacity. The proposed FIP would require 88 percent removal of plant wide SO_2[2] on an annual rolling average basis. This would result in plant wide annual average SO_2 emissions being limited to 0.24 lb/mmBtu on coal projected to be burned in 2016.[3] The proposed FIP would require NO_x emissions not to exceed 0.85 lbs/mmBtu for Units 1 and 2, and 0.65 lbs/mmBtu for Units 3, 4 and 5.

The Four Corners Power Plant is located on the Navajo Reservation and the Tribal Authority Rule has stated that state air quality regulations could not be enforced against facilities on the Indian Reservation. It is imperative that a firm agreement between the Navajo Tribe and the Federal EPA be negotiated to guarantee that the Federal EPA will be the regulatory and enforcement agency for the Four Corners Power Plant (FCPP) clean up process. This will allow the Federal EPA to regulate and enforce emission limits for SO2, NOx, PMs and opacity that are specified in the new EPA Region 9 FIP.

Update: On April 30, 2007, EPA Region 9 finalized a Federal Implementation Plan (FIP) that establishes federally enforceable emission limits for SO_2, NO_x, total PM_{10} and opacity. The FIP requires 88 percent removal of plant wide SO_2 on an annual rolling average basis, and limits three-hour average SO_2 emissions to 17,900 lbs/hr plant wide. This would result in plant wide annual average SO_2 emissions being limited to 0.24 lb/mmBtu on coal projected to be burned in 2016. The FIP requires that 30-day rolling average NO_x emissions are not to exceed 0.85 lbs/mmBtu for Units 1 and 2, and 0.65 lbs/mmBtu for Units 3, 4 and 5; and daily NO_x emissions are not to exceed 335,000 lbs. PM emissions are limited to 0.050 lbs/mmBtu, and opacity is limited to 20%, except for one six-minute period per hour not to exceed 27%.

Presumptive BART at FCPP

Sulfur Dioxide

The application of presumptive BART limits for SO_2 on Units 1-5 at FCPP would result in a plant wide annual average of 0.15 lbs/mmBtu or 93 percent removal based on future coal. Estimated emissions for 2018[4] are shown in Figures 2 & 3 for emissions at the current level of control, the proposed level of control under the FIP, a scenario with BART applied to Units 3-5 only, and BART applied to Units 1-5. All options assume control efficiency remain constant within each given scenario.

Emissions under the scenario where presumptive BART for SO_2 is applied to all Units are only slightly less than current emission rates. However, applying presumptive BART for SO_2 would result in an emission limit specified as an allowable rate of emissions (lbs/mmBtu). The FIP would allow SO_2 removal to decline from the present 92 percent to 88 percent. Additionally, the FIP specifies the SO_2 limit in terms of efficiency, or percent removal of SO_2 from the coal being burned. If the coal quality decreases (to higher sulfur coal), as it is projected to do, the limit in terms of percent removal will allow for more emissions of SO_2; thus, it is preferable to have an emission rate as the controlling limit.

Nitrogen Oxides

The application of presumptive BART limits for NO_x on Units 1-3 (0.23 lb/mmBtu), and combustion controls and SCR on Units 4 & 5 would result in a plant wide annual average of 0.16 lb/mmBtu. Application of presumptive BART for Units 4 & 5 would result in a rate of 0.45 lbs/mmBtu for those Units. Estimated emissions for 2018 are shown in Figure 4 for emissions at the current level of control, the current Title V permit limit, the proposed level under the FIP, a scenario with BART applied to Units 1-5, and a scenario that applies BART to Units 1-3 and applies combustion controls and SCR to Units 4 & 5. NO_x emissions under the proposed FIP would be significantly higher than current rates; application of presumptive BART for NO_x to all Units would reduce NO_x 30 percent from current rates; application of presumptive BART to Units 1-3, and combustion controls plus SCR on Units 4 & 5 would result in the most significant reductions of NO_x: 70 percent from current rates, and less than half from the scenario with BART on all Units.

Since Units 4 and 5 are cell burners, they are inherently very high emitters of NO_x, and, because of the narrowness of their furnaces, are very difficult to reduce emissions by combustion controls alone (combustion controls alone represent presumptive BART). EPA has recognized that the presumptive limits (and associated technologies) do not preclude the application of different technologies: "[b]ecause of differences in individual boilers, however, there may be situations where the use of such controls would not be technically feasible and/or cost-effective. . . . Our presumption accordingly may not be appropriate for all sources."[5] The cost (see below) of SCR on these Units is comparable to combustion controls—which may not be technically feasible—and SCR will result in significantly more reductions of NO_x. Currently, Units 4 and 5 each emit twice the NO_x as Units 1, 2 and 3 individually.[6] Therefore, SCR is the best reasonable method to achieve meaningful NO_x reductions at Units 4 and 5.

Reduction of NO_x is particularly important to improve visibility at Mesa Verde National Park, which is 52 km away from FCPP. As shown in Figures 1a, 1b and 1c, visibility has degraded at Mesa Verde over the past decade, and the portion of degradation due to nitrate has increased (while there has been no trend in degradation due to sulfate).

II. Description of how to implement

A. Mandatory or voluntary:

This option represents a mandatory, federally enforceable emission limit.

B. Indicate the most appropriate agency(ies) to implement:

The regulating agency for this facility is EPA Region 9.

III. Feasibility of the option

FCPP is currently at or below the presumptive BART limit for SO_2. No additional controls are needed.
Differing Opinion: FCPP does not consistently operate at or below presumptive BART limit for SO_2

For Units 1-3, the Environmental Protection Agency's suggested presumptive BART for NO_x limits "reflect highly cost-effective technologies."[7] EPA, in fact, performed visibility impact and cost-effectiveness analyses on the presumptive limits. Therefore, the BART presumptive limits of NO_x are considered to be technical and economically feasible.

EPA states that the majority of units could meet presumptive NO_x limits with current combustion control technology for between $100 and $1000 per ton of NO_x removed. If more advanced combustion controls are required, the cost would be less than $1500 per ton of NO_x removed. Furthermore, EPA states that "by the time units are required to comply with any BART requirements . . . more refinements in combustion control technologies will likely have been developed by that time. As a result, we believe our analysis and conclusions regarding NO_x limits are conservative.[8]

Application of EPA's Cost Tool model for Units 4 & 5 predicts that NO_x could be reduced by 70% to the levels shown by application of combustion controls plus SCR at a cost of $409 - $464 per ton of NO_x removed.[9] EPA states that the average cost of combustion controls on cell burners (presumptive BART) is $1021 per ton. The average cost of applying SCR to cyclone units, (which for those units is presumptive BART), is $900 per ton.

IV. Background data and assumptions used

Historical emissions data comes from EPA's Clean Air Markets Division databases. Projected capacity utilizations come from the Western Regional Air Partnership's "11_state_EGU_analysis" projections.

EPA's cost tool: http://www.epa.gov/airmarkt/arp/nox/controltech.html

V. Any uncertainty associated with the option

Uncertainties in FCPP's ability to meet the BART presumptive limit for SO_2 include future coal quality. Future emissions of SO_2, NO_x and PM10 will depend on future utilization, which at this point has been predicted.

VI. Level of agreement within the work group for this mitigation option To Be Determined.

VII. Cross-over issues to the other Task Force work groups None.

Citations:

[1] http://cfpub.epa.gov/gdm/index.cfm?fuseaction=factstrends.top_bypollutant
[2] Although EPA limits annual average SO_2 emissions to 12.0% of the SO_2 produced by the plant's coal-burning equipment, its method of calculating the amount of SO_2 produced is not consistent with EPA's "Compilation of Air Pollutant Emission Factors," (AP-42) which assumes that 12.5% of the sulfur in sub-bituminous coal (as burned at FCPP) is never converted to SO_2 but is retained in the ash collected in the boiler. When this sulfur retention is taken into consideration, the EPA proposal represents 86% control of potential SO_2 emissions.
[3] BHP, the supplier of coal to FCPP, has projected coal quality to 2016 when its contract expires. This estimate is based upon 2016 coal with a heating value of 8,890 Btu/lb and a sulfur content of 0.85%. (document prepared by C. Nelson, BHP Navajo Coal Company on 27 February 2006 and submitted by Sithe Global as part of the Desert Rock permit application).
[4] All projections are based upon fuel quality estimates from the coal supplier and WRAP utilization growth projections.
[5] 70 F.R. 39134 (July 6, 2005).
[6] http://www.epa.gov/airmarkets/emissions/prelimarp/05q4/054_nm.txt
[7] 70 F.R. 39131, July 6, 2005.
[8] 70 F.R. 39135, July 6, 2005.
[9] http://www.epa.gov/airmarkt/arp/nox/controltech.html

Figure 1.a. WRAP Total Extinction Trends

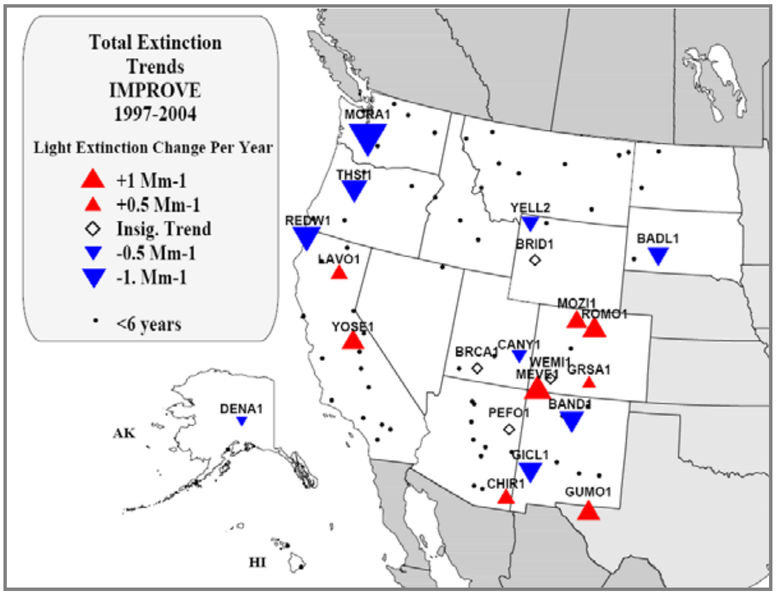


Figure 1.b. WRAP Sulfate Extinction Trends

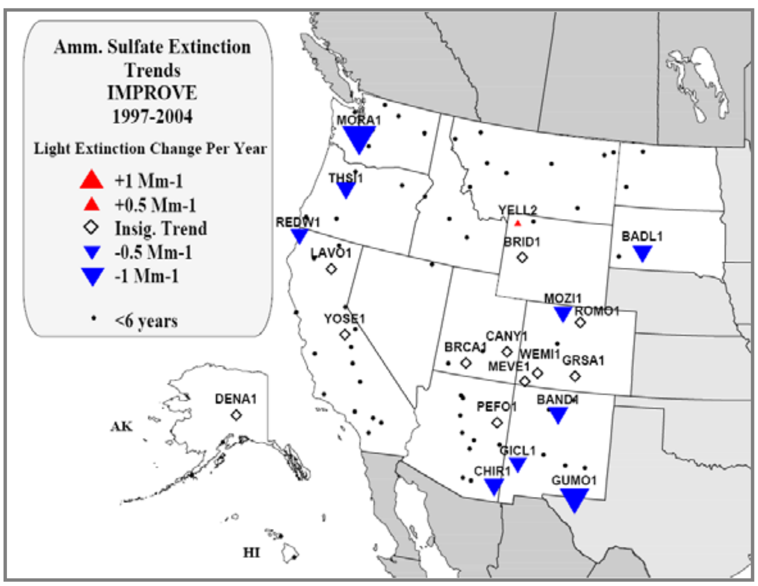


Figure 1.c. WRAP Nitrate Extinction Trends

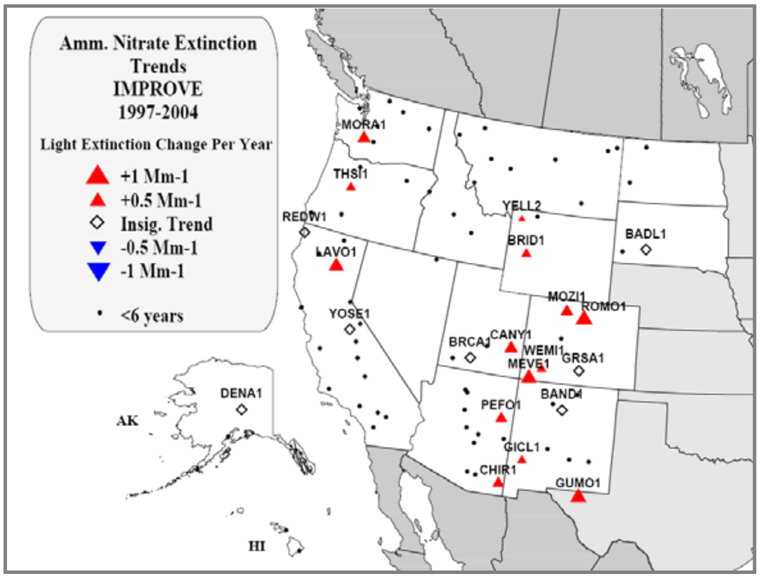


Figure 2. FCPP Emission Trends

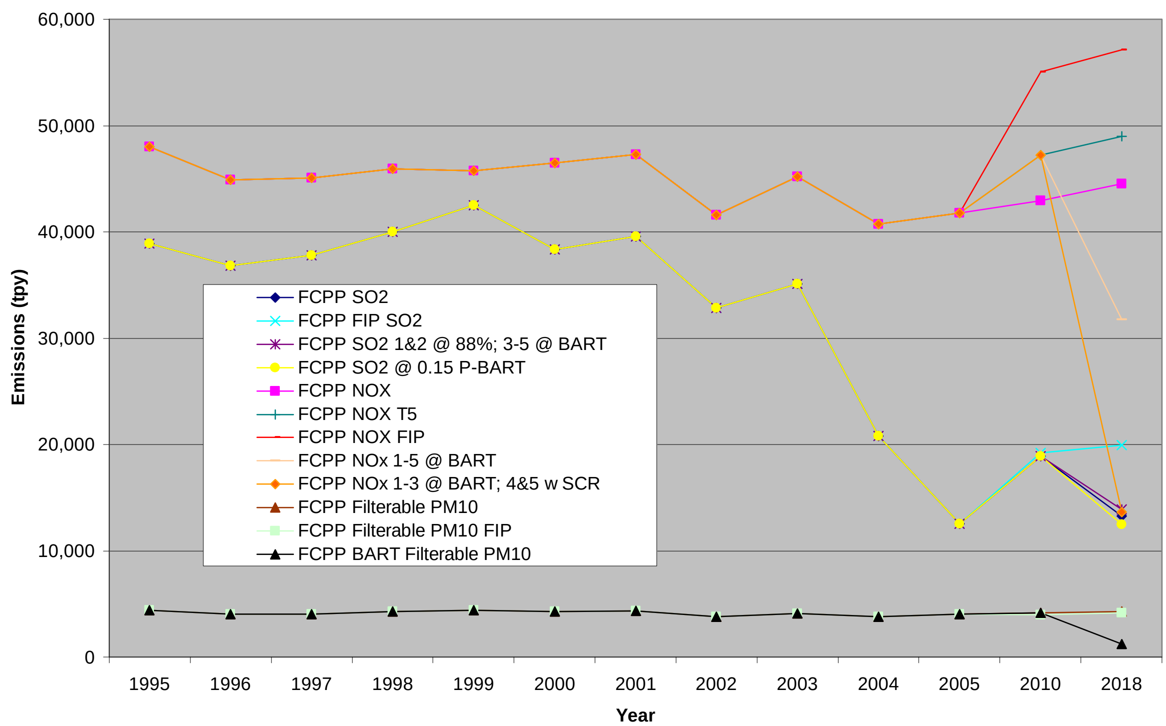


Figure 3. FCPP 2018 SO2 vs. Control Strategy

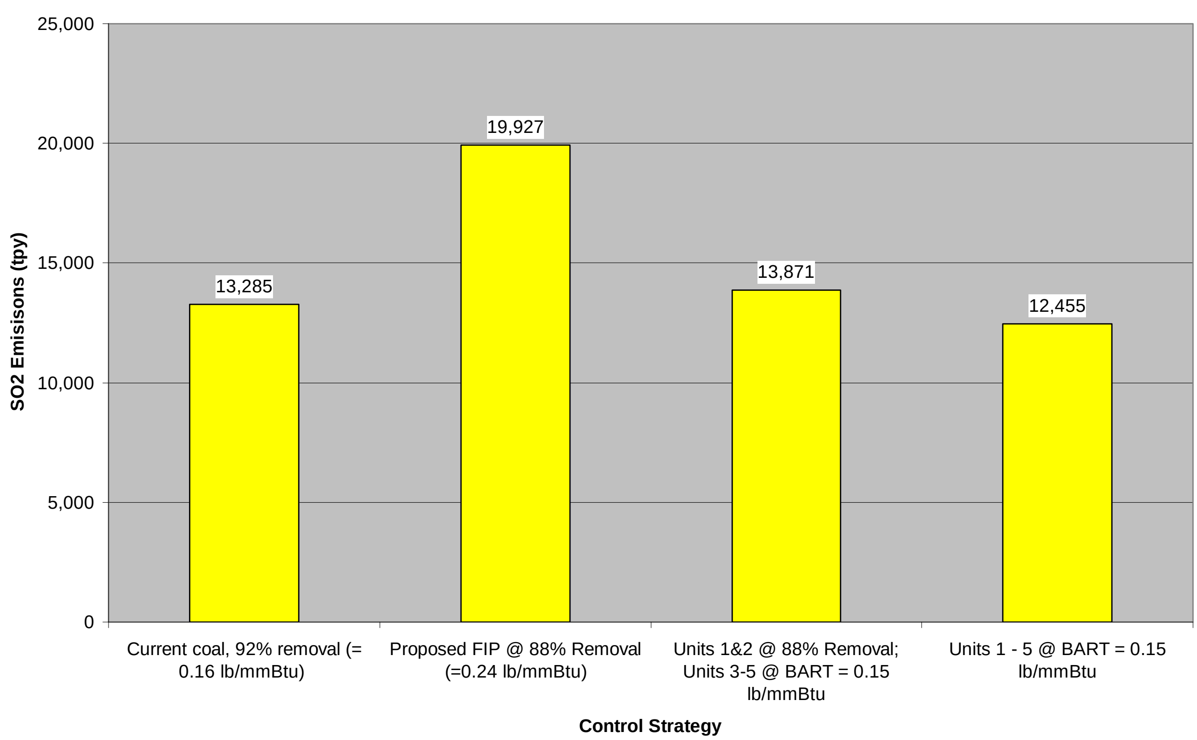
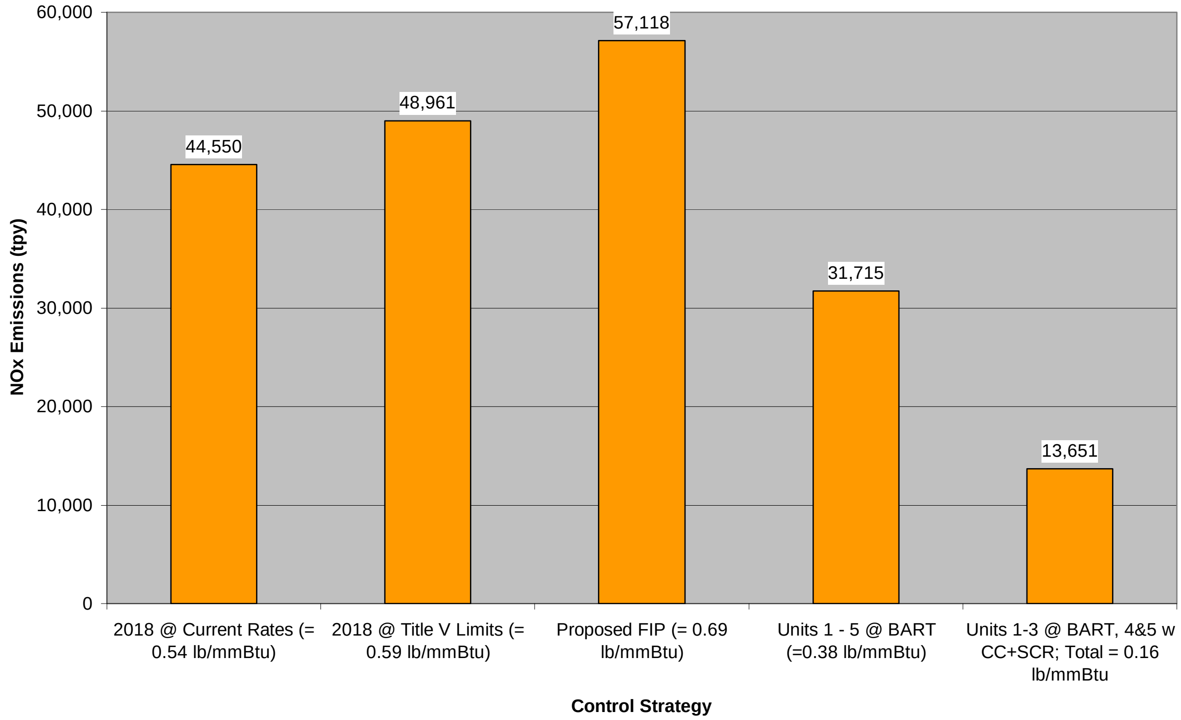


Figure 4. FCPP 2018 NOx Emissions vs Control Strategy



Mitigation Option: Control Technology Options for San Juan Generating Station

I. Description of the mitigation option

Summary of Option

Presumptive emission limits for NO_x should be applied to all units at San Juan Generating Station (SJGS).

Background: Best Available Retrofit Technology (BART)

SGJS consists of four pulverized coal fired boilers. Each boiler was built between 1962 and 1977 and emits more that 250 tons per year of visibility-impairing pollution. The units are therefore subject to the Best Available Retrofit Technology (BART) requirements under the Regional Haze Rule. The BART requirements mandate industrial facilities that cause or contribute to regional haze to control emissions of visibility-impairing pollutants. The Clean Air Act (CAA) states that BART guidelines shall apply to fossil-fueled fired generating power plants with a capacity greater than 750 MW (§169A(b)). The CAA does not exempt individual units of any size from BART requirements.

For Electric Generating Units with a capacity greater than 200 MW, the Environmental Protection Agency (EPA) has provided (rebuttable) presumptive emission limits for sulfur dioxide (SO_2) and nitrogen oxides (NO_x), based on boiler size, coal type and controls already in place. EPA "analysis indicates that these controls are likely to be among the most cost-effective controls available for any source subject to BART, and that they are likely to result in a significant degree of visibility improvement." (70 FR 39131, July 6, 2005). Those presumptive limits (which are 30-day rolling averages) are:

- Unit #1 is 359 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #2 is 359 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #3 is 555 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #4 is 555 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu

Background: SJGS Emissions

In March of 2005, Public Service of New Mexico (PSNM) entered into a Consent Decree to reduce SO_2, NO_x, and PM_{10} emissions by 2010 at SGJS to the levels shown below:

- NO_x = 0.30 lb/mmBtu (30-day rolling average). The Consent Decree requires that San Juan minimize NOx emissions. The 0.30 lb/mmBtu limit will be evaluated after 1 year of operation and adjusted to a lower limit if possible.
- SO_2 = 90% annual average control,[1] not to exceed 0.250 lb/mmBtu for a seven-day block average.
- PM_{10} = 0.015 lb/mmBtu (filterable)

PSNM will replace all four existing Electrostatic Precipitators with Fabric Filters. San Juan currently meets the 0.015 lb/mmBtu limit with the existing Electrostatic Precipitators. The fabric filters (baghouses) will be installed primarily to reduce opacity spikes during upset conditions and to allow the addition of activated carbon for mercury control.

PSNM will have to meet the 90% SO_2 control requirement regardless of the coal quality. Current coal quality averages about 1.4 lb SO_2/mmBtu (uncontrolled). Therefore, ninety percent control would result in an annual average emission rate of 0.14 lb/mmBtu, and would likely satisfy the presumptive BART requirement.

Presumptive BART for NO_x at SJGS

The Consent Decree (CD) level for NO_x is 0.30 lb/mmBtu; the BART presumptive level for NOx is 0.23 lb NO_x/mmBtu. The BART presumptive level is lower than that in the CD, and therefore will result in lower emissions. Figure 1 depicts the historical trends of SO_2 and NO_x at SJGS, as well as future trends out to 2018 based upon available information on coal quality[2] and capacity utilization.[3] Emission increases after 2010 are due to increased utilization. The decreased NO_x emissions are based on the assumption that SJGS Units 1-4 will meet the presumptive BART limit for NO_x by 2018.

The presumptive BART level of 0.23 lbs/mmBtu was developed based on Powder River Basin (PRB) Coal. Although both the PRB and the San Juan Basin coals are considered sub bituminous, San Juan coal has properties of bituminous coal which has a higher presumptive BART level.

Reduction of NO_x is particularly important to improve visibility at Mesa Verde National Park, which is 43 km away from SJGS. As shown in Figures 1a, 1b and 1c, visibility has degraded at Mesa Verde over the past decade, and the portion of degradation due to nitrate has increased (while there has been no trend in degradation due to sulfate).

II. Description of how to implement

A. Mandatory or voluntary:

This option represents a mandatory, federally enforceable emission limit.

B. Indicate the most appropriate agency(ies) to implement:

The regulating agency for this facility is the State of New Mexico.

III. Feasibility of the option

The Environmental Protection Agency's suggested presumptive BART limits "reflect highly cost-effective technologies."[4] EPA, in fact, performed visibility impact and cost-effectiveness analyses on the presumptive limits. Therefore, the BART presumptive limits of NO_x are considered to be technical and economically feasible.

EPA states that the majority of units could meet these NO_x limits with current combustion control technology for between $100 and $1000 per ton of NO_x removed. If more advanced combustion controls are required, the cost would be less than $1500 per ton of NO_x removed. Furthermore, EPA states that "by the time units are required to comply with any BART requirements . . . more refinements in combustion control technologies will likely have been developed by that time. As a result, we believe our analysis and conclusions regarding NO_x limits are conservative.[5]

The most accurate cost estimate for SJGS to meet the BART limit for NO_x is likely to be from EPA's Cost Tool model, which estimates costs for specific units at specific emission rates.[6] That model predicts that the presumptive BART limits for NO_x could be met at costs of $355 - $501 per ton.

San Juan is currently in the process of doing a BART Analysis. It will be submitted to the NMED in June 2007.

IV. Background data and assumptions used

Historical emissions data comes from EPA's Clean Air Markets Division databases. Projected capacity utilizations come from the Western Regional Air Partnership's "11 State EGU Analysis" projections.
EPA's Cost Tool Model: http://www.epa.gov/airmarkt/arp/nox/controltech.html

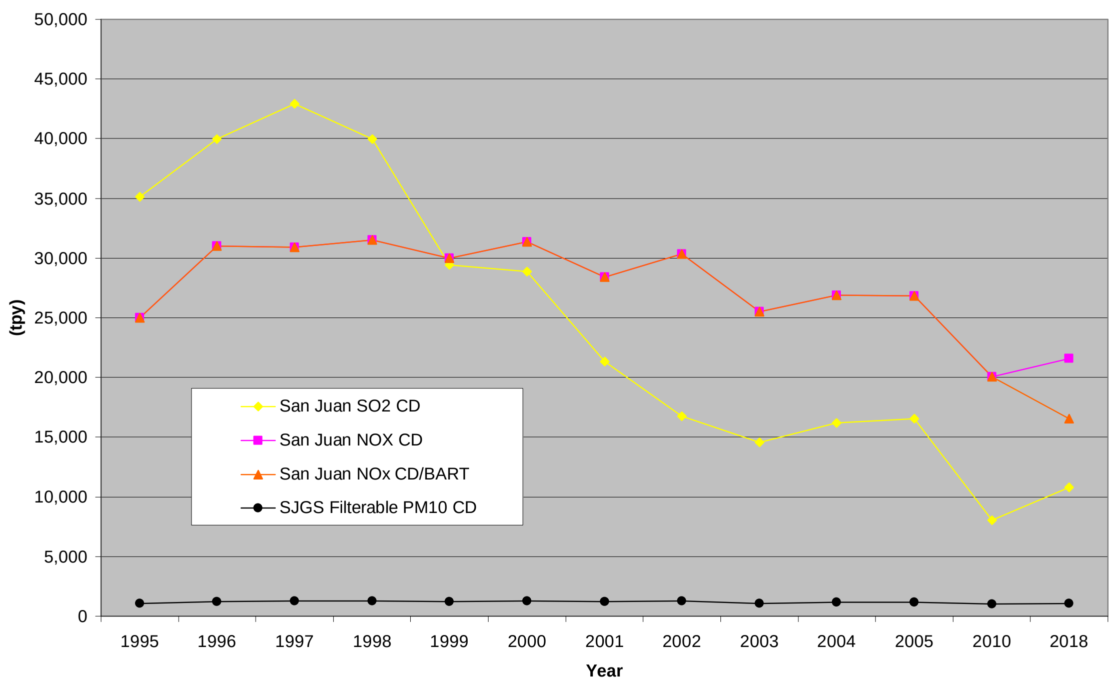
V. Any uncertainty associated with the option (Low, Medium, High)
Uncertainties in SJGS's ability to meet the BART presumptive limit for SO2 include future coal quality. Future emissions of SO_2, NO_x and PM10 will depend on future utilization, which at this point has been predicted.

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups None.

Citations:
[1] Based upon scrubber inlet and outlet SO_2 concentrations, as measured by Continuous Emission Monitors.
[2] Document prepared by C. Nelson, BHP Navajo Coal Company on Feb. 27, 2006 and submitted by Sithe Global as part of the Desert Rock permit application.
[3] Western Regional Air Partnership, 11 State EGU Analysis spreadsheet
[4] 70 F.R. 39131, July 6, 2005.
[5] 70 F.R. 39135, July 6, 2005.
[6] http://www.epa.gov/airmarkt/arp/nox/controltech.html

Figure 1. San Juan SO2 & NOx



EXISTING: OPTIMIZATION

Mitigation Option: Energy Efficiency Improvements

I. Description of the mitigation option
Upgrades or major repairs to existing power plants are potentially subject to the New Source Review process. This includes projects that are undertaken to improve the efficiency of the plants (i.e., produce more power while burning less or the same amount of fuel.) This process has been so difficult and cumbersome that these projects are often not cost-effective to pursue. The regulatory agencies should work closely with the utilities to simplify the process, remove barriers and to encourage these efficiency improvements.

II. Description of how to implement
A. Mandatory or voluntary:

B. Indicate the most appropriate agency(ies) to implement
Regulating agencies:
EPA Region 9 Air Programs, Navajo Nation EPA, New Mexico Air Quality Bureau

III. Feasibility of the option
A. Technical:
B. Environmental:
C. Economic:

IV. Background data and assumptions used:

V. Any uncertainty associated with the option (Low, Medium, High):
Medium

VI. Level of agreement within the work group for this mitigation option.
TBD

VII. Cross-over issues to the other Task Force work groups:
None

Mitigation Option: Enhanced SO_2 Scrubbing

I. Description of the mitigation option

Enhanced SO_2 scrubbing on existing power plants in the Four Corners area has resulted in significant SO_2 reductions. This mitigation option suggests further efforts to develop and optimize SO_2 scrubbing at San Juan Generating Station and Four Corners Power Plant.

Background:

Wet Flue-Gas Desulfurization System:

Wet scrubbing, or wet flue gas desulfurization (FGD), is the most frequently used technology for post-combustion control of SO_2 emissions. It is commonly based on low-cost lime-limestone in the form of aqueous slurry. Lime is calcium oxide, CaO; Limestone is $CaCO_3$. The slurry brought into contact with the flue-gas absorbs the SO_2 in it. $CaSO_4$-$2H_2O$, Gypsum, is formed as a byproduct (1).

Gas flow per unit cross sectional area, which determines scrubber diameter, must be low enough to minimize entrainment. Mass transfer characteristics of the system determine absorber height. These vessels and the accompanying equipment used for slurry recycle, gypsum dewatering, and product conveyance tend to be quite large. Some variations of this technology produce high quality gypsum for sale. Less pure waste product may be sold for use in cement production. If neither of these options is practiced, the scrubber waste must be disposed of in a sludge pond or similar facility (2).

The wet scrubber has the advantage of high SO_2 removal efficiencies, good reliability, and low flue gas energy requirements (1).

What is being done:

San Juan Generating Station has initiated an Environmental Improvement program under its consent decree that includes enhanced SO_2 scrubbing. Projections show that optimization of SO_2 scrubbing will result in a reduction of SO_2 from the current emission rate of 16,569.5 tons/yr to an emissions rate of 8,900 tons/yr by the year 2010 (3, 4, 5). This would translate as an increase in SO_2 removal efficiency from 81% to 90% as required by the consent decree.

The Consent Decree that San Juan has entered into will require a minimum of 90% removal of SO2.

Four Corners Power Plant has also made significant improvements in SO_2 emissions control efficiency. APS, in partnership with the Navajo Nation, several environmental groups and federal agencies, conducted a test program to determine if the efficiency of the existing scrubbers at Four Corners Power Plant could be improved from the recent historical level of 72% SO_2 removal to 85%. The test program, which was completed in spring of 2005, was successful and the plant was able to achieve a plant-wide annual SO_2 removal of 88%. In fact, data indicates that a 92% removal, or 0.16 lbs/mmBtu SO2 limit was achieved. Some parties involved in the test program have agreed that a new rule should propose to require 88% removal efficiency for the Four Corners Power Plant (6). Parties are also interested, however, in a mass emissions limit as opposed to removal rate to protect against air quality degradation from higher sulfur coal.

The way “removal” is used here is based on including the amount of sulfur retained in the ash. For FCPP, this amounts to about 2% “bump-up” of the control efficiency. So, 88% removal is the equivalent of 86% control. By contrast, both the NM regulations and the SJGS consent decree require that the control efficiency across the scrubber be measured by CEMs before and after the scrubber.

72% SO_2 removal resulted in approximately 22,450 Tons/yr SO_2 emissions. The new emissions control removal efficiency of 88% translated to 12,500 Tons/yr SO2 emissions in 2005.

Further advances in SO_2 scrubber optimization should be explored and implemented as they become available. It may be possible to achieve over 90% SO_2 removal efficiencies with enhanced SO_2 scrubbing on existing power plants in the 4C area

During 2005, FCPP demonstrated that it can achieve better than 90% control of SO_2.

Benefits: SO_2 removal increase. Possible co-benefits are increased particulate removal, and also mercury removal.
Tradeoffs:
Burdens: Cost to existing power plants including: optimization controls or additional retrofit technologies.

II. Description of how to implement
A. Mandatory or voluntary
Voluntary emissions reductions that are above and beyond new standards

Differing Opinion: A FCPP FIP that reflects the capabilities of the control equipment and coal supply

B. Indicate the most appropriate agency(ies) to implement
New Mexico Air Quality Bureau
EPA Region 9 and Navajo Nation EPA

III. Feasibility of the option
A. Technical: technology is available and feasible.
B. Environmental: Optimized SO2 scrubbing could result in SO_2 control efficiency above 90%.
C. Economic: Improving existing emissions control process through optimization is often less expensive than retrofitting plant with entirely new emissions control equipment.

IV. Background data and assumptions used:
1. El-Wakil, M.M. Power Plant Technology; McGraw-Hill, New York: 2002.
2. Clean Coal Technology Topical Report #13, May 1999, DOE, "Technologies for the combined Control of Sulfur Dioxides and Nitrogen Oxides from Coal-fired Boilers"
3. Current estimated SO_2 emissions from Four Corners area power plants (4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV9)
4. San Juan Generating Station (SJGS) presentation for 4CAQTF, August 9, 2006, "SJGS Emissions Control Current and Future"
5. Clean Air Markets – Data and Maps – 2005 Unit Emissions Report – Emissions for San Juan Generating Station & Four Corners Steam Electric Station
6. Final rule for Four Corners Power Plant:
ENVIRONMENTAL PROTECTION AGENCY, 40 CFR Part 49, [EPA-R09-OAR-2006-0184; FRL-], Source-Specific Federal Implementation Plan for Four Corners Power Plant; Navajo Nation

V. Any uncertainty associated with the option
Medium – SO_2 scrubbing control efficiencies have increased recently. Optimization of SO_2 scrubbing systems have limitations.

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups None

EXISTING: ADVANCED NO_x CONTROL TECHNOLOGIES

Mitigation Option: Selective Catalytic Reduction (SCR) NO_x Control Retrofit

I. Description of the mitigation option,
To reduce NOx emissions from the existing power plants in the Four Corners area, a Selective Catalytic Reduction system could be retrofitted to San Juan Generating Station and Four Corners Power Plant.

Selective Catalytic Reduction, SCR, uses ammonia or urea along with catalysts in a post-combustion vessel to transform NO_x into nitrogen and water. It can achieve the 0.15-pound-per-million Btu standard (1).

Some eastern EGUs retrofitted with SCR have achieved 0.05 lb/mmBtu. Based on recent permit applications and boilers in the east that have retrofitted with SCR, this technology can typically achieve a 90 percent reduction in NO_x emissions.

Ammonia is used as the reducing agent. It is injected into the flue gas stream and then passes over a catalyst. The ammonia reacts with nitrogen oxides and oxygen to form nitrogen and water.

The main Selective Catalytic Reduction reaction is $4NH_3 + 4NO + O_2 \rightarrow 4\ N_2 + 6H_20$ (2)

Supplemental description of Selective Catalytic Reduction available from US EPA, AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01) (for Desert Rock Energy Facility)

This report further discusses technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging or poisoning, ammonia slip emissions, and design of the ammonia injection system (3).

And the SCR system
The SCR system is comprised of a number of subsystems. These include the SCR reactor and flues, ammonia injection system and ammonia storage and delivery system (3).

Based on heat input and emissions data from the Acid Rain Program:
Currently NO_x emissions from San Juan Generating Station are on the order of 0.42 lbs/mmBtu or 26,800 Tons/yr.
Currently NOx emissions from the Four Corners Power Plant are approximately 0.57 lbs/mmBtu or 40,700 Tons/yr (4). Note: FCPP is the largest NOx-emitting EGU is the US.

The proposed Desert Rock Energy facility is planning to build their facility with Selective Catalytic Reduction technology to control NO_x emissions. They expect 85-90% control of NOx. The permit allowed NOx emissions will be 0.060 lbs/mmBtu fuel input (2).

Retrofitting a Selective Catalytic Reduction to existing power plants would be much more difficult than installing equipment with the construction of the plant; however, it is an option to greatly reduce NOx emissions from existing sources. It may be able to reduce emissions from existing sources by as much as 50%.

Differing Opinion: Applying SCR to existing plants may be more difficult than new installation; it is not a given. SCR has been successfully applied in the East in response to the CAIR rule. Retrofits at eastern utilities subject to the NOx SIP Call and CAIR typically set a 90% reduction goal. The vintage EPA Cost Tool database assumes 70% control by SCR, and SCR has improved dramatically since then.

Benefits: It is an option to greatly reduce NOx emissions from existing sources. It may be able to reduce emissions from existing sources by as much as 50% - 90%+. SCR may have some co-benefit reductions of Mercury emissions.

Tradeoffs:
Ammonia that is not reacted will "slip" through into exhaust. Ammonium salts could also form thus increasing loading to the particulate collection stage as PM10 (and PM2.5) (2). This is less likely with lower sulfur coal.
SCR tends to increase the reaction of SO_2 to SO_3 and increases the formation of acid mists. This could require additional treatment of the flue gas. This is less likely with lower sulfur coal.

Any analysis should compare the cost of SCR to the costs of combustion controls.

Application of EPA's Cost Tool model for the Four Corners Power Plant, Units 4 & 5 predicts that NO_x could be reduced by 70 percent to the levels shown by application of combustion controls plus SCR at a cost of $409 - $464 per ton of NO_x removed. EPA states that the average cost of combustion controls on cell burners (presumptive BART) is $1021 per ton. The average cost of applying SCR to cyclone units, (which for those units is presumptive BART), is $900 per ton.

Burdens: Retrofit costs to existing power plants. Installation may be cost prohibitive for some existing plants because of the physical layout of the plant. Safety issue with handling of ammonia for use as reducing agent

II. Description of how to implement
A. Mandatory or voluntary
Retrofit program could be mandatory or voluntary
SCR application could be considered in the context of BART.

B. Indicate the most appropriate agency(ies) to implement
State Air Quality Bureaus, Federal EPA, Industry

III. Feasibility of the option
A. Technical – commercially available

B. Environmental – high reduction efficiencies demonstrated 85-90+%.
Sulfur content of the coal is an important factor in use of SCR. The low-sulfur coals burned in the 4 Corners area should be more compatible with SCR. SCR is being widely applied to a variety of bituminous and sub-bitumninous coals, especially in the East. Requiring catalyst replacement is an economic issue.

The SCR process is subject to catalyst deactivation over time (2).

C. Economic – Retrofit costs. Additional maintenance costs

*Cumulative Effects Work Group – How would 50%-90% emissions reductions from the two existing power plants affect visibility and ozone?
*Monitoring Work Group – Would it be possible to measure ammonia slip in the exhaust gases?

IV. Background data and assumptions used

1. US Department of Energy (DOE) Pollution Control Innovations Program
http://www.fossil.energy.gov/programs/powersystems/pollutioncontrols/index.html

2. Development of Nitric Oxide Catalysts for the Fast SCR Reaction, Matt Crocker, Center for Applied Energy Research, University of Kentucky (2005)

3. US EPA, AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01) (for Desert Rock Energy Facility)
*A good description of Selective Catalytic Reduction is available on pp.9-10 of the US EPA, Ambient Air Quality Impact Report, Best Available Control Technology discussion, for the Desert Rock Energy Facility.

4. Clean Air Markets – Data and Maps – 2005 Unit Emissions Report – Emissions for San Juan Generating Station & Four Corners Steam Electric Station
Heat input for all 4 units at San Juan Generation Station 127,629,979 mmBtu in 2005.
Heat input for all 5 units combined at 4Corners Power Plant 141,394,388 mmBtu in 2005.

5. San Juan Generating Station (SJGS) presentation for 4CAQTF, August 9, 2006, "SJGS Emissions Control Current and Future"

V. Any uncertainty associated with the option High.

Differing Opinion: The success of SCR in reducing NO_x emissions is a proven technology

VI. Level of agreement within the work group for this mitigation option To Be Determined.

VII. Cross-over issues to the other Task Force work groups

Oil & Gas industry may also look at SCR as a method to reduce natural gas compressor NO_x emissions

Mitigation Option: BOC LoTOx™ System for the Control of NOx Emissions

I. Description of Mitigation Option

Belco BOC LoTox is an oxidation technology for flue gas NOx control. It was developed in recent years and has become commercially successful and economically viable as an alternative to ammonia and urea based technologies. Older commercial technologies such as Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR), which reduce NOx to nitrogen using ammonia or urea as an active chemical, are limited in their use for high particulate and sulfur containing NOx streams such as from coal-fired combustors, or are unable to achieve sufficient NOx removal to meet new NOx regulation levels. In contrast, oxidation technologies convert lower nitrogen oxides such as nitric oxide (NO) and nitrogen dioxide (NO2) to higher nitrogen oxides such as nitrogen sesquioxide (N2O3) and nitrogen pentoxide (N2O5). These higher nitrogen oxides are highly water soluble and are efficiently scrubbed out with water as nitric and nitrous acids or with caustic solution as nitrite or nitrate salts. NOx removal in excess of 90% has been achieved using oxidation technology on NOx sources with high sulfur content, acid gases, high particulates and processes with highly variable load conditions.

The BOC LoTOx™ System is based on the patented Low Temperature Oxidation (LTO) Process for Removal of NOx Emissions, exclusively licensed to BOC Gases by Cannon Technology. This technology has met the stringent cost and performance guidelines established by the South Coast Air Quality Management District in Diamond Bar, CA and has set new lower limits for Best Available Control Technology (BACT) and Lowest Achievable Emissions Reduction (LAER). The LoTOx™ System for NOx Control uses oxygen to produce ozone as the primary treatment chemical using an ozone generator. The oxidation of NOx using ozone is a naturally occurring process in the atmosphere. The absorption of higher nitrogen oxide by water to form nitric acid is also a naturally occurring process in the atmosphere, resulting in “acid rain”. The LoTOx™ System reproduces these naturally occurring processes under controlled conditions within an enclosed system. This treatment method produces the treatment chemical, ozone, on demand from gaseous oxygen in the exact amount required for oxidation of the NOx.

A demonstration was conducted at Southern Research Institute’s (SRI) Combustion Research Facility, Birmingham, AL using a mobile demonstration trailer. The test was the first in a series of tests planned to demonstrate the effectiveness of ozone for oxidation and removal of NOx emissions from SRI’s coal-fired combustor. The results from the tests demonstrated that the LoTOx™ System is highly effective for removal of NOx emissions from as high as 350 ppmv NOx to below 50 ppmv NOx levels without significant residual ozone in the exhaust stream. The LoTOx™ System is very selective for NOx removal, oxidizing only the NOx and therefore efficiently using the treatment chemical, ozone, without causing any significant SOx oxidation and without affecting the performance of the downstream SOx scrubber. Furthermore the ozone/NOx ratios required to produce desired NOx oxidation are less than the predicted stoichiometric amounts. Various types of coals and fuel types will be used in the combustor. The information gathered will be used for the design of commercial LoTOx™ Systems for effective and efficient NOx removal at utility power plants and other large-scale NOx sources. [1]

Chemistry

The LoTOx process is based on the excellent solubility of higher order nitrogen oxides. Typical combustion processes produce NOx streams that are approximately 95% NO and 5% NO2. Both NO and NO2 are relatively insoluble in aqueous streams, therefore, wet scrubbers will only remove a few percent of NOx from the flue gas stream. Species Solubility at 25°C and 1 atm

NO 0.063 g/l, NO2 1.260 g/l

The LoTOx process uses ozone to oxidize NO and NO2 to N2O5 ,which is highly soluble, and by wet scrubbing N2O5 is easily and quickly converted to HNO3, based on the following reactions:

NO + O3 -> NO2 + O2

$2NO_2 + O_3 \rightarrow N_2O_5 + O_2$
$N_2O_5 + H_2O \rightarrow 2HNO_3$
Both N_2O_5 and HNO_3 are extremely soluble in water. N_2O_5 reacts instantaneously with water forming HNO_3. Since HNO_3 is so highly soluble (approaching infinity) it is difficult to measure, and therefore reliable solubility data is not available in published literature. However, HNO_3 mixes with water in all proportions and therefore the N_2O_5 to HNO_3 reaction is irreversible in the presence of water. [2]

Benefits: Low Temperature, No chemical slip
Tradeoffs:

Burdens:
Ozone unused in the treatment process produces no health hazards to plant workers nor to the environment. The ozone is injected into flue gas stream where it reacts with relatively insoluble NO and NO_2 to form N_2O_3 and N_2O_5, which are highly water soluble, and are easily and efficiently removed and neutralized in a wet scrubbing system. [1]

II. Description of how to implement
A. Mandatory or voluntary
LoTOx could be the answer to achieve required limits under regional haze rule. This control technology could be an option to meet mandatory emissions limits

B. Indicate the most appropriate agency(ies) to implement
4 Corners Power Plants would implement new technology as an integrated component of emissions control system

III. Feasibility of the option
A. Technical: Low temperature reaction is good. Ozone generation and other LoTOx system components are well understood technologies used in other applications.
B. Environmental: Pilot scale demonstrations showed 90% removal, very high reduction efficiencies
C. Economic: Retrofit technologies can be expensive on existing power plants.

This technology has only been tested on pilot plants and there are no full scale installations. The technology should therefore, at this point, be considered not technically feasible.

IV. Background data and assumptions used
1. DEMONSTRATION AND FEASIBILITY OF BOC LoTOx™ SYSTEM FOR NOx CONTROL ON FLUE GAS FROM COAL-FIRED COMBUSTOR abstract, presented at 2000 Conference on SCR & SNCR for NOx Control/BOC,
http://www.netl.doe.gov/publications/proceedings/00/scr00/ANDERSON.PDF
2. CARB Innovative Clean Air Technology, "Low Temperature Oxidation System Demonstration," BOC paper 1999, http://arbis.arb.ca.gov/research/apr/past/icat99-2.pdf
3. DuPont BELCO LoTOx Technology homepage
http://www.belcotech.com/products/nox.html

V. Any uncertainty associated with the option
Medium, any retrofit technology has a degree of uncertainty. It can be difficult and expensive to retrofit emissions control technology that the plant was not originally designed for.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

EXISTING: OTHER RETROFIT TECHNOLOGIES

Mitigation Option: Baghouse Particulate Control Retrofit

I. Description of the mitigation option
Installation of baghouses at existing power plants in the Four Corners area could reduce particulate emissions by approximately 25% or more. Baghouses, or fabric filters, as they are often called, collect fly ash and other particulate matter from the coal combustion process like large vacuum cleaners. Typically a baghouse removes more than 99.8 % of the fly ash.

The original design for the two major power plants in the 4 Corners area was for electrostatic precipitators (ESPs). The ESPs on San Juan Generating Station remove approximately 99.7 % of the particulate matter from the exhaust stream. This exceeds current state and federal emissions requirements (0.1 lbs/mmBtu and 0.05 lbs/mmBtu).

The San Juan generating station is currently undergoing a series of environmental improvements between 2007 and 2009 including designing for a 0.015 lbs/mmBtu particulate limit. PNM will install fabric filters (baghouses) for all four SJGS units collect particulate emissions. The ESPs at San Juan will remain in place but will be de-energized. It is believed that a portion of the ash will continue to be removed in the ESPs (because of gravity separation) but they will not be considered a control device. One of the reasons to install the baghouses was because of PNM's commitment for Activated Carbon Injection for the removal of mercury. An ESP would not have been efficient in the collection of the activated carbon. An additional benefit of the baghouse is the reduction of opacity spikes that are caused by an increase in unburned carbon in the flyash. This unburned carbon is caused by combustion problems associated with the operation of the low-NOx burners and is not efficiently collected by an ESP. Also, we will not know until the Baghouses are installed and operational, but we do not anticipate that the actual particulate emissions will be significantly less than the current emissions. However, the permit requirement will be reduced from 0.05 lbs/mmBtu to 0.015 lbs/mmBtu.

Since all units at San Juan and Units 4 & 5 at Four Corners currently have or will have baghouses in the near future, this option will only apply to Units 1,2 & 3 at Four Corners.

Benefits: Current reported levels of particulate emissions at major power plants in the 4Corners area include: San Juan Generating Station emits approximately 673 Tons/yr, approximately .011 lbs/mmBtu; 4 Corners Power Plant emits approximately 1,187 Tons/yr, approximately .017 lbs/mmBtu (see 4CAQTF_PowerPlant_WorkGroup_ FacilityDataTableV10). Baghouse installation may result in improved particulate removal efficiencies. If baghouses could reduce emissions to .010 lbs/mmBtu, this option could lead to over 500 tons per year reduction of particulates collectively from the two largest coal fired power plants in the region.

Differing Opinion: The benefits (500 ton reduction of particulates) may be over estimated because San Juan and Four Corners Unit 4 & 5 will have baghouses and will perform at or close to the 0.01 lbs/mmBtu. The only units that would see a reduction would be Four Corners Units 1,2 & 3.

Burdens: Cost of baghouse installation on power plants

II. Description of how to implement
A. Mandatory or voluntary
Voluntary or consent decree

B. Indicate the most appropriate agency(ies) to implement
Power Plants would install

III. Feasibility of the option
A. Technical: Technology is available commercially

B. Environmental: Feasible

C. Economic: Expensive to install new technology

IV. Background data and assumptions used
1. San Juan Generating Station (SJGS) Emissions Control Current and Future, presentation for 4CAQTF, May 2006 ,http://www.nmenv.state.nm.us/aqb/4C/Docs/SanJuanGeneratingStation.pdf

2. 4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10

3. Clean Air Markets – Data and Maps – 2005 Unit Emissions Report – Emissions for San Juan Generating Station & Four Corners Steam Electric Station
Heat input for all 4 units at San Juan Generation Station 127,629,979 mmBtu in 2005.
Heat input for all 5 units combined at 4Corners Power Plant 141,394,388 mmBtu in 2005.

4. San Juan Environmental Improvement Upgrades Fact Sheet,
http://www.pnm.com/news/docs/2005/0310_sj_facts.htm

V. Any uncertainty associated with the option
Medium.

VI. Level of agreement within the work group for this mitigation option
TBD.

VII. Cross-over issues to the other Task Force work groups
None.

Mitigation Option: Mercury Control Retrofit

I. Description of the mitigation option
Existing power plants in the Four Corners area should evaluate the installation of mercury removal technology to reduce mercury emissions. According to EPA's 2005 Toxic Release Inventory report the San Juan Generating Station released 770 lbs and Four corners Power Plant released 625 lbs of mercury into the air. Activated carbon injection technology is the most likely control technology at this time. This technology has been demonstrated in several pilot studies.

The Clean Air Mercury Rule (CAMR) will require the reduction of mercury emissions from power plant beginning in 2010 with further reductions in 2018. This rule will also require the installation of mercury Continuous Emissions Monitoring systems by January 1, 2009.

San Juan Generating Station will have mercury control (activated carbon injection) on all four units by 2010 and Mercury CEMs on 2 units by 2008 and all 4 units by 2009.

II. Description of how to implement
A. Mandatory or voluntary: Mandatory and/or Voluntary

B. Indicate the most appropriate agency(ies) to implement
Regulating agencies:
EPA Region 9 Air Programs, Navajo Nation EPA, New Mexico Environment Department

III. Feasibility of the option
A. Technical: The injection of activated carbon into the flue gas stream has been demonstrated in pilot studies to remove mercury. However, there have not been any long-term applications of this technology. Also the effectiveness of this technology has not been demonstrated on the type of coal in the San Juan Basin so the actual removal efficiency of the technology is unknown. Nevertheless, many new coal-fired power plant projects are proposing installation of activated carbon injection.

B. Environmental: Mercury emissions will be reduced, however, the addition of activated carbon to the fly ash will make the ash unsuitable for sale to the cement/concrete industry and will increase the amount of fly ash that will have to be disposed.

C. Economic: The cost of additional equipment for ACI injection is relatively small, however, the annual operating and maintenance cost can be significant because of the cost of the activated carbon. Also there currently is a limited supply of activated carbon. The increase cost for ash disposal could be significant. Also, ACI injection requires a bag house or fabric filter for particulate control. This cost would be significant if this technology would have to be retrofitted to existing units.

IV. Background data and assumptions used N/A.

V. Any uncertainty associated with the option Medium.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

EXISTING: STANDARDS

Mitigation Option: Harmonization of Standards

I. Description of the mitigation option,

This option would require existing power plants to meet the most stringent standard of any governmental agency in the region, i.e., the strictest state, federal, or tribal standard. At present facilities are subject to varying standards depending on where they are located, even though emissions affect the entire area and beyond.

This option is limited to existing power plants on the basis that new power plants are held to Best Available Current Technology (BACT) limitations on controlled emissions, which are usually much lower than current state or federal air standards.

One of problems in the Four Corners area is the aging fleet of large power plants. These older power plants have significantly higher emissions than potential new sources. The two largest generating stations in the Four Corners Region, Four Corners Power Plant (FCPP) and the San Juan Generating Station (SJGS), are regulated by different agencies even though they are within 30 miles of each other. San Juan Generating Station is being held to more stringent regulations by the New Mexico Air Quality Bureau regulations.

The burden of this requirement to adopt more stringent regulations would fall on the owners of the facilities and might also lead to the eventual retirement of some older Four Corner area power plants. However, the long-term effect of this rule, especially if applied to other multi-state regions over time, might lead to standardized regulations, also a benefit, if the new standards converged on the most stringent requirement.

II. Description of how to implement

This rule should be mandatory and phased in over a designated period of time.

A valuable lesson is to be learned from the Four Corners Power Plant jurisdiction quandary. The Navajo Tribe ruled that the State of NM cannot regulate and enforce FCPP emissions. Very recently, a lawsuit was filed against the Federal EPA regarding FCPP emissions. This lawsuit may have expedited the current series of action by the Federal EPA such as public sessions, the FIP, etc. The FCPP is on tribal land, but the air emissions affect the entire Four Corners area. Somehow, a regulatory agency responsible for governing and enforcing emissions of present and future power plants and oil and gas facilities should be agreed upon by all entities.

The area's ozone problem is an example of why it is important to have one regulatory agency. The Four Corners area has unusually high volumes of ground level ozone. The Four Corners Ozone Task Force (FCOTF) has been working for the past several years on ozone mitigation options. The FCOTF is working closely with EPA Region 6. Recently EPA Region 9 officials came to the area to talk about the proposed Desert Rock coal fired power plant. This area's ozone problems were not addressed by EPA Region 9 in the Desert Rock Proposed PSD Permit. In order to avoid costly environmental oversights and/or confusion, only one EPA Region should be designated as the Federal Agency to regulate and enforce in an area such as the Four Corners.

Differing Opinion: Implementing this option could initially be voluntary, as it would ultimately require changes to the Clean Air Act and/or Code of Federal Regulations to address tribal authority over air programs, and the role of the Federal Implementation Plan.

III. Feasibility of the Option

Technical issues: none, technology currently exists to meet the most stringent existing requirement

Environmental issues: Benefits of stricter standards are intuitive. The following are examples of significant disparities in state and federal limits:

For example, the current State permit limit for NOx emissions from San Juan Generating Station is 0.46 lbs/mmBtu. The federal limits for NOx at Four Corners Power Plant are 0.65 – 0.85 lbs/mmBtu. San Juan Generating Station NOx emissions rate is approx. 0.4 lbs/mmBtu or 26,800 Tons/yr. Four Corners Power Plant, under the federal regulation, emits approx 0.6 lbs/mmBtu or approx 41,700 tons/yr

The state limit for SO_2 emissions from San Juan Generating Station is 0.65 lbs/mmBtu. The federal limit applied to Four Corners Power Plant is 1.2 lbs/mmBtu. The state permit limit for PM emissions from San Juan Generating Station is 0.05 lbs/mmBtu. The Federal PM standard is 0.1 lbs/mmBtu.

Economic: Implementation of resulting standards could be expensive. Experience of the political unit currently having the strictest standard could provide some data on the cost. In any case, the standard, even though not industry-wide, would be applicable area-wide and therefore more fair to competing power generators

Political issues: resistance would be great, just as it is now to tightening of standards. Effective implementation of this idea might require creation of a Four Corners regional authority or special district, which might require enabling legislation: the difficulty of accomplishing this is unknown.

IV. Background data and assumptions

The Federal/State PSD rules are applied industry wide for new power plants and existing power plants with major modifications in NAAQS attainment areas. Existing power plants in different jurisdictions continue to be regulated by different standards even though they are in the same air basin. This option would be a step in harmonizing standards. It is clear that the two plants we have heard from could meet tighter standards, especially when applied industry-wide; but since they are not required to do so, they cannot get their owners to support meeting them. It is intuitive that if any installation in the Four Corners region using San Juan Basin coal can meet the tightest standard, they all can over a reasonable period of time.

Green House Gases Such as Carbon Dioxide –
It is becoming more and more apparent that Global Warming or Climate Changes is a world wide problem. Reductions in carbon dioxide emissions, one of the green house gases, should be addressed in the Mitigation Options for all existing and future coal fired power plants in the San Juan Basin. The carbon dioxide issue will have to be dealt with sooner or later and the sooner, the better.

New Mexico Environmental Regulations for Air Quality may be found at:
http://www.nmenv.state.nm.us/aqb/regs/index.html

V. Any uncertainty associated with the option

There is a high level of uncertainty in getting something like this passed politically and how long it would take is an unknown.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues Oil and Gas Work Group, Other Sources Work Group.

EXISTING: MISCELLANEOUS

Mitigation Option: Emission Fund

I. Description of the mitigation option

This option would establish an emissions fund for emitters of one or more air pollutants of concern, such as nitrogen oxides. Sources emitting more than a specified amount annually would pay by the ton emitted into a fund that would then be used for environmental improvement projects. There should be no maximum number of tons over which fees wouldn't be paid.

The fund should be used for environmentally beneficial projects, to be decided by the administering body (see below). One option is to have a grant system whereby applications are made to the fund by anyone—regulated community, environmental community, public, academia, etc—and the administering body would have set criteria against which they evaluated each request. Another option is to specify the allowable uses of the fund, such as for the development or investment in innovative technologies.

Benefits: Ideally, emitters required to pay per ton emitted would have an incentive to emit less. To make this incentive effective, the fee per ton would need to be relatively high. A thorough search of similar programs and any evaluations of those programs should be done to determine what fee level would provide an effective incentive. Monetary incentives could result in emission reductions at significantly lower costs than "command and control" regulation. Emission fees also work to "internalize the externalities" involved in air emissions and environmental degradation by recognizing and attempting to account for the social costs of the operations of the emitters.

Burdens: the primary burden would be on the emitter, to pay into the fund based on annual emissions. There would be some administrative burden, lessened by using existing reporting and oversight frameworks to implement the program.

II. Description of how to implement

A. Mandatory of voluntary: Payment into an emission fund would be mandatory for a defined size or class of sources

B. Most appropriate agency to implement: These programs have generally been administered by state agencies. Tribal air quality agencies could also develop and implement an emissions fund. An oversight committee or the air quality entity with regulatory authority would have authority to administer the fund. The committee or board should have members representing the regulated community, environmental community and general public.

The program could be phased in: fees per ton of emissions of specified pollutant(s) could gradually be increased over 5-10 years. The program could be based on existing permitting systems: fees would be based on the number of tons reported emitted, via existing reporting requirements within permits or any other existing framework for reporting.

III. Feasibility of the option

Emissions funds for air pollution are used in France, Japan and many states as well. There are no technical feasibility issues associated with this option.

IV. Background data and assumptions used

Stavins, R. (Ed.) (2000). *Economics of the Environment (4th Ed.)*. WW Norton: New York, New York.

New Hampshire Code of Administrative Rules, Chapter Env-A 3700: *NOx Emissions Reduction Fund for NOx-Emitting Generation Sources*.
Ohio EPA *Synthetic Minor Title V Facility Emission Fee Program*.
http://www.epa.state.oh.us/dapc/synmin.html. (via statute--need cite).

Texas Administrative Code, Title 30, Part 1, Chapter 101, Subchapter A, Rule sec. 101.27: *Emissions Fees*

V. Uncertainty

VI. Level of agreement within workgroup

VII. Cross-over issues to other workgroups

The oil and gas industry could be subject to the emissions fund.

PROPOSED POWER PLANTS: DESERT ROCK ENERGY FACILITY

Mitigation Option: Desert Rock Energy Facility Stakeholder Funding to and Participation in Regional Air Quality Improvement Initiatives such as Four Corners Air Quality Task Force

I. Description of the mitigation option

Sithe Global and other stakeholders in Desert Rock Energy Facility will provide time and resource commitments to participate in inter-agency environmental initiatives to improve air quality in the Four Corners area.

Background:
Sithe Global Power, LLC proposes to construct a 1,500 Megawatt hybrid dry cooled coal-fired electric power-generating plant south of Farmington in northwestern New Mexico, per the project development agreement entered into with Diné Power Authority (1).

The proposed Desert Rock Energy Facility is located within the New Mexico portion of the Four Corners Interstate Air Quality Control Region. The area is currently designated as attainment for all regulated pollutants: nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter less than 10 microns in aerodynamic diameter (PM_{10}), lead, and ozone (regulated as volatile organic compounds (VOC) and oxides of nitrogen (NO_x)). There are concerns, however, with air pollution in the area and the effects on human health, visibility, and other air quality related values. The Facility's surrounding area is classified as Class II. The nearest Class I area is the Mesa Verde National Park, which is located approximately 75 kilometers (km) north of the site. The Grand Canyon National Park is located approximately 290 km west of the site (3). There are nine National Park Service Class I areas and six Forest Service Class I areas within 300 km of this proposed facility.

While the Desert Rock Energy Facility is using newer environmental emission control technology that on average have higher reduction efficiencies than existing facilities, the proposed power plant will still be adding substantial NO_2, SO_2, particulate, and other emissions to the Four Corners Area. See appendix 1.

Industry support would help to provide the resources necessary to ensure the air quality in the Four Corners, including our National Ambient Air Quality Standards (NAAQS) attainment, is maintained. There are substantial stakeholder interests in having air quality cleaner than simply meeting the NAAQS, for example, to improve visibility.

Desert Rock Energy LLC submitted a set of comments on the Four Corners Air Quality Task Force report during the public comment period. Desert Rock's comments included a discussion of a Voluntary Regional Air Quality Improvement Plan, CO_2 emissions, and IGCC in relation to the proposed facility. The comments are located in an appendix at the end of the Power Plants section.

Benefits: Environmental initiatives will be supported by industries that contribute to the air quality issues. Much needed financial support will be provided to regional environmental initiatives. Information resources will be provided to help in the environmental regulation planning process.

Tradeoffs: None

Burdens: Sithe Global and other stakeholders will provide time and resource commitment to participate in inter-agency environmental initiatives in the Four Corners area.

II. Description of how to implement

A. Mandatory or voluntary

Voluntary or mandatory

Differing Opinion: Mandatory: because of the fact that the Four Corners Area is already heavily polluted by several industrial sources such as the Four Corners Power Plant and the San Juan Generating Facility, over 19,000 oil and gas wells (over 12,500 new wells are planned in the next two decades), a fast growing population, more motor vehicles, etc.

B. Indicate the most appropriate agency(ies) to implement

Environmental Protection Agency (EPA) Air Programs

Desert Rock Energy Project voluntary participation

Differing Opinion: According to an article in the December 11, 2006 "Farmington Daily Times" titled "Navajo Nation to Partially Own Desert Rock", "Representatives from the Dine Power Authority (DPA) say they will operate the proposed Desert Rock Power Plant with at least one degree of separation from the Navajo Nation Environmental Protection Agency (NNEPA) which will have oversight of the project." This should be a major concern. The Desert Rock Power Plant if built, must be closely monitored and enforcement must be very strict. There are concerns that a conflict of interest may exist. The Federal EPA should be the governing agency.

III. Feasibility of the option

Feasible.

IV. Background data and assumptions used

Literature cited

(1) Desert Rock Energy Project FACT SHEET #1, DEC 2004 (http://www.desertrockenergy.com/)

(2) 4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10

(3) AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)

V. Any uncertainty associated with the option

Low.

VI. Level of agreement within the work group for this mitigation option.

To Be Determined.

VII. Cross-over issues to the other Task Force work groups

None.

Table 1. Estimated Maximum Annual Potential Emissions from Desert Rock Energy Facility [Source: AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)]

Pollutant	PC Boilers (tpy)	Auxiliary Boilers (tpy)	Emergency Generators (tpy)	Fire Water Pumps (tpy)	Material Handling (tpy)	Project Estimated Emissions
NOx	3,315	7.13	2.26	0.41	n/a	3,325
CO	5,526	2.55	0.17	0.031	n/a	5,529
VOC	166	0.17	0.11	0.019	n/a	166

SO_2	3,315	3.61	0.068	0.012	n/a	3,319
PM[2]	553	1.02	0.083	0.015	16.1	570
PM_{10}[3]	1,105	1.68	0.077	0.014	12.9	1,120
Lead	11.1	0.00064	0.00012	0.0000022	n/a	11.1
Fluorides	13.3	neg	neg	neg	neg	13.3
H_2SO_4	221	0.062	0.002	0.0004	n/a	221
Mercury	0.057	0.000071	neg	neg	n/a	0.057

[1]tpy -tons per year
[2]PM is defined as filterable particulate matter as measured by EPA Method 5.
[3]PM_{10} is defined as solid particulate matter smaller than 10 micrometers diameter as measured by EPA Method 201 or 201A plus condensable particulate matter as measured by EPA Method 202. EPA is treating PM_{10} as a surrogate for $PM_{2.5}$.

Mitigation Option: Emissions Monitoring for Proposed Desert Rock Energy Facility to be used over Time to Assess and Mitigate Deterioration to Air Quality in Four Corners Area

I. Description of the mitigation option

The present proposed monitoring permit requirements for Desert Rock Energy Facility address only measurement of permit standards while there is another category of monitoring which could and should be done. This category would be data needed or useful for the evaluation of mitigation options in the present or the future.

PROPOSED ADDITIONAL MONITORING

a. PM2.5 continuous monitoring requirement.

The Four Corners region has several class 1 areas and a long term requirement by the EPA for improving visibility. PM2.5 is a critical element in this problem and future mitigation of it will require precise knowledge of the relative contributions from multiple and varied sources. This could come about by inclusion in the EPA permit conditions or by the company adding it to what they are doing to protect themselves from future finger pointing. Either way the data needs to be publicly available so those evaluating mitigation options have the use of it.

Total filterable PM CEMs have been certified by EPA. EPA contends that there is no currently certified method to continuously monitor PM_{10} or $PM_{2.5}$. However, there are some PM CEMs vendors that suggest CEMS can be modified to monitor a certain particulate size fraction.

b. Speciated Mercury (Hg) stack emission plus a plume contact measurement.

This region now has several lakes where restrictions of fishing exist because of Hg levels in the fish. The sources of Hg are multiple (geology, mining, oil & gas, agriculture, and power plants) to devise a proper mitigation plan the Hg species will need to be known so that sources can be identified and contribution determined. Models which predict Hg species in the environment from those found in the stack have shown problems. (Hg Speciation in Coal-fired Power Plant Plumes Observed at Three Surface Sites in the SE U.S.,Environ. Sci. Technol.2006, 40, 4563-4570:Modeling Hg in Power Plant Plumes, Environ. Sci. Technol,2006, 40,3848-3854) For this reason sampling at plume ground contact needs to be done to determine species for our environment and plant and coal types as the Hg enters the environment since we can not count on modeling to give correct Hg speciation. The stack sampling should be required under the permit plume surface contact samples however might be a cooperative venture between state or tribal personnel and the company. (State or Tribal personnel taking the sample and this sample then run by the company with the stack sample.)

c. VOC sampling in addition to that presently specified in the permit.

While the VOC's are nowhere near levels that would cause general health problems they are critical to the processes involved in the visibility problem which needs addressing. VOC's react in the plume after emission and change. A measurement of the VOC's after the initial reaction in the plume would be advantageous since it would give what is present to react to give the visibility problems. The VOC's present after this initial reaction is usually predicted by modeling however the literature indicates there are some problems with this approach measurements made at the plume ground contact could be a joint operation. State or Tribal personnel might collect a sample with the company running the sample with their stack sample.

II. Description of how to implement

A. Mandatory or voluntary

Desert Rock Energy Facility would be responsible for facility monitors

There are concerns that there are not enough monitors in place in the Four Corners Area and that the existing monitors are not placed in optimum locations. Several more monitors in logical locations must be installed in order to accurately measure emissions. The Federal, State, and Tribal EPA agencies should be responsible for collection and analyzing samples. The Four Corners Power Plant and the San Juan Generating Station are among the dirtiest coal fired power plants in the Nation. Desert Rock must be placed under strict scrutiny. The Four Corners Area is already close to ground level ozone levels of non-attainment. The area cannot afford further degradation of the air quality.

B. Indicate the most appropriate agency(ies) to implement
State or Tribal personnel might collect and analyze some samples

III. Feasibility of the option
A. Technical
B. Environmental
C. Economic

*Monitoring Work Group – assess the feasibility (technical, environmental, and economic) of conducting the proposed monitoring.
*Cumulative Effects Work Group – Will the proposed additional monitoring in this mitigation option be useful in assessing the Desert Rock Energy Facility point source contributions to the cumulative Four Corners area air quality?

IV. Background data and assumptions:

V. Any uncertainty associated with the option (Low, Medium, High)
Low

VI. Level of agreement within the work group for this mitigation option
TBD

VII. Cross-over issues to the other source groups
None

Mitigation Option: Coal Based Integrated Gasification Combined Cycle (IGCC)

I. Description of the mitigation option

Consideration of IGCC technology, as an alternative to a pulverized coal fired boiler, should be considered in the BACT analysis.

Sithe Global Power, LLC proposes to construct a 1,500 Megawatt hybrid dry cooled coal-fired electric power-generating plant south of Farmington in northwestern New Mexico, per the project development agreement entered into with Diné Power Authority (1).

The proposed Desert Rock Energy Facility is located within the New Mexico portion of the Four Corners Interstate Air Quality Control Region. The area is currently designated as attainment for all regulated pollutants: nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter less than 10 microns in aerodynamic diameter (PM_{10}), lead, and ozone (regulated as volatile organic compounds (VOC) and oxides of nitrogen (NO_x)). There are concerns, however, with air pollution in the area and the effects on human health, visibility, and other air quality related values. The Facility's surrounding area is classified as Class II. The nearest Class I area is the Mesa Verde National Park, which is located approximately 75 kilometers (km) north of the site. The Grand Canyon National Park is located approximately 290 km west of the site (2). There are nine National Park Service Class I areas and six Forest Service Class I areas within 300 km of this proposed facility.

On July 7, 2006, the Environmental Protection Agency (EPA) released a technical report titled "The Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies." The Report provides information on the environmental impacts and costs of the coal-based integrated gasification combined cycle (IGCC) technology relative to conventional pulverized coal (PC) technologies.

"IGCC is a power generation process that uses a gasifier to transform coal (and other fuels) to a synthetic gas (syngas), consisting mainly of carbon monoxide and hydrogen. The high temperature and pressure process within an IGCC creates a controlled chemical reaction to produce the syngas, which is used to fuel a combined cycle power block to generate electricity. Combined-cycle power applications are one of the most efficient means of generating electricity because the exhaust gases from the syngas-fired turbine are used to create steam, using a heat recovery steam generator (HRSG), which is then used by a steam turbine to produce additional electricity (3)."

Consideration of IGCC technology, as an alternative to a pulverized coal fired boiler, was not included in the BACT analysis for the Desert Rock Energy Facility (2).

Desert Rock Energy LLC submitted a set of comments on the Four Corners Air Quality Task Force report during the public comment period. Desert Rock's comments included a discussion of IGCC. Please see the comment in its entirety in the appendix to the Power Plants section.

<u>Benefits:</u> For traditional pollutants such as nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter (PM) and mercury (Hg), IGCC is inherently lower polluting than the current generation of traditional coal-fired power plants. IGCC also has multi-media benefits, as it uses less water than Pulverized Coal facilities. IGCC also produces a solid waste stream that can be a useful byproduct for producing roofing tiles and as filler for new roadbed construction. IGCC also has the potential to reduce solid waste by using as fuel a combination of coal and renewable biomass products (3).

IGCC is considered one of the most promising technologies to reduce the environmental impacts of generating electricity from coal. EPA has undertaken several initiatives to facilitate the development and deployment of this technology

IGCC thermal performance (efficiency and heat rate) is significantly better than current generation pulverized coal technologies in the US;

The Capture of CO2 emissions from IGCC plants would be cheaper and less energy intensive than in conventional coal plants (3, 6)

<u>Tradeoffs:</u>
<u>Burdens:</u> IGCC has 10 – 20 % higher capital costs than conventional PC plants [3]
When carbon capture becomes mandatory, that cost disadvantage will likely disappear.

II. Description of how to implement

A. Mandatory or voluntary

Mandatory to look at IGCC as a Best Available Control Technology option for future power plants in the Four Corners area

Permit levels could be set based upon IGCC performance. It would be up to the source how to meet those limits with whatever technology it chooses.

This could be a new legislative requirement at the State or Tribal level

B. Indicate the most appropriate agency(ies) to implement

Policy options for use of Integrated Gasification Combined Technology could be developed by Environmental Protection Agency (EPA), Department on Energy (DOE), New Mexico Energy, Minerals, and Natural Resources Department (NMEMNRD).

*EPA could designate IGCC as a Best Available Control Technology.

Differing Opinion:

Assuming that coal gasification is an innovative fuel combustion technique for producing electricity from coal, EPA does not believe Congress intended for an "innovative fuel combustion technique" to be considered in the BACT review when application of such a technique would redesign a proposed source to the point that it becomes an alternative type of facility. In prior EPA decisions and guidance, EPA does not consider the BACT requirement as a means to redefine the basic design of the source or change the fundamental scope of the project when considering available control alternatives. Therefore, the question is whether IGCC results in a redefinition of the basic design of the source if the permittee is proposing to build a supercritical pulverized coal (SCPC) unit. EPA's view is that applying the IGCC technology would fundamentally change the scope of the project and redefine the basic design of the proposed source if a supercritical pulverized coal unit was the proposed design. Accordingly, consistent with our established BACT policy, we would not require an applicant to consider IGCC in a BACT analysis for a SCPC unit. Thus, for such a facility, we would not include IGCC in the list of potentially applicable control options that is compiled in the first step of a top-down BACT analysis. Instead, we believe that an IGCC facility is an alternative to an SCPC facility and therefore it is most appropriately considered under Section 165(a)(2) of the CAA rather than section 165(a)(4).

Four Corners state legislatures and/or Tribal Nations could legislate that IGCC be considered?

III. Feasibility of the option

A. Technical:
Development and implementation of IGCC technology is relatively new compared with the PC technology that has hundreds or thousands of units in operation globally. Currently in the US there are two gasification unit installations using coal to make electric power as the primary product. The two IGCC plants in commercial operation include the Tampa Electric Polk Power Station in Florida and the Wabash River Coal Gasification Repowering Plant in Indiana. Each has been in operation since the mid-1990s. Recently, however, a number of companies have announced plans to build and operate additional IGCC facilities in the US (3).

These plants have yet to maintain better than 80% availability after more than 10 years of operation. Improved process control strategies are needed to ensure optimum operation over the full range of operating conditions. Real time coal quality analysis is needed to stabilize the coal gasifier process. Several areas of instrumentation development are warranted by the challenging physical conditions of the high temperature, abrasive, slagging gasifier environment. Other areas of the IGCC process face unique challenges that require development efforts to achieve the high availability rate needed for economic viability.

IGCC plants have not been demonstrated larger than 300 MW. For Desert Rock, more/larger gasifiers and several combustion turbines would be needed to attain 1500 MW. This technology is promising, but needs much development funding before the investment community would take on the risk of building such a large IGCC facility.

B. Environmental: This is a process control option

C. Economic: IGCC has higher capital costs than conventional PC plants (3).

IGCC has not demonstrated the typical 85-95% PC plant availability factors necessary for viable on-going profitable operation.

Historically, concerns about operational reliability and costs presented issues of uncertainty for IGCC technology and impeded its deployment. Such conditions are changing toward the more rapid advancement of the IGCC option. IGCC is a versatile technology and is capable of using a variety of feed stocks. In addition to various coal types, feed stocks can include petroleum coke, biomass and solid waste. Along with electricity production, IGCC facilities are able to co-produce other commercially desirable products that result from the process. Some of these products include steam, oxygen, hydrogen, fertilizer feed stocks and Fischer-Troph fuels (3).

The operational versatility noted above for IGCC technology may mitigate the risk of higher costs. In addition, under the Energy Policy Act of 2005, there are provisions for tax credits and a DOE Loan Guarantee Program to provide incentives to facilitate the deployment of IGCC technology.
In 1994 EPA established the Environmental Technology Council (ETC) to coordinate and focus the Agency's technology programs. The ETC strives to facilitate innovative technology solutions to environmental challenges, particularly those with multi-media implications. The Council has membership from all EPA technology programs, offices, and regions and meets on a regular basis to discuss technology solutions, technology needs and program synergies. One of the technologies identified as a promising option to address the production of energy from coal in an environmentally sustainable way is IGCC. This technical report is part of the ETC initiative and supports the combined efforts of EPA and the Department of Energy to advance the use of IGCC technology (3).

IV. Background data and assumptions used:

(1) Desert Rock Energy Project FACT SHEET #1, DEC 2004 (http://www.desertrockenergy.com/)

(2) AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)
(3) Technical Report on the Environmental Footprint and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, Fact Sheet: http://www.epa.gov/airmarkets/articles/IGCCfactsheet.html
(4) Wabash River IGCC Topical Report 2000 – www.fossil.energy.gov/programs/powersystems/publications/Clean_Coal_Topical_Reports/topical20.pdf
(5) Pioneering Gasification Plants (DOE) – http://www.fe.doe.gov/programs/powersystems/gasification/gasificationpioneer.html
(6) Scientific American, September 2006 article, "What to do about Coal," pp. 68-75
(7) ISA-2005 "I & C Needs of Integrated Gasification Combines Cycles" Jeffrey N. Phillips, Project Manager, Future Coal Generation Options, Electric Power Research Institute – presented at the 15th Annual Joint ISA POWID/EPRI Controls and Instrumentation Conference, 5-10 June 2005, Nashville, TN

V. Any uncertainty associated with the option

Medium. Integrated Gasification Combined Cycle (IGCC) is still a relatively new technology. There are coal gasification electric power plants in the US and other nations.

VI. Level of agreement within the work group for this mitigation option

To Be Determined

VII. Cross-over issues to the other Task Force work groups:

None

Mitigation Option: Desert Rock Energy Facility Invest in Carbon Dioxide Control Technology

I. Description of the mitigation option

Sithe Global Power, LLC proposes to construct a 1,500 Megawatt hybrid dry cooled coal-fired electric power-generating plant south of Farmington in northwestern New Mexico, per the project development agreement entered into with Diné Power Authority (1).

The proposed Desert Rock Energy Facility is located within the New Mexico portion of the Four Corners Interstate Air Quality Control Region. The area is currently designated as attainment for all regulated pollutants: nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter less than 10 microns in aerodynamic diameter (PM10), lead, and ozone (regulated as volatile organic compounds (VOC) and oxides of nitrogen (NOx)). The Facility's surrounding area is classified as Class II. The nearest Class I area is the Mesa Verde National Park, which is located approximately 75 kilometers (km) north of the site. The Grand Canyon National Park is located approximately 290 km west of the site (2). There are nine National Park Service Class I areas and six Forest Service Class I areas within 300 km of this proposed facility.

CO_2 emissions are not regulated; however, they are the primary Greenhouse gas that causes global warming.

In June 2005, the Climate Change Advisory Group was created in New Mexico as the result of an executive order from the Governor. The Climate Change Advisory Group (CCAG) is tasked with preparing an inventory of current state (New Mexico) Greenhouse gas emissions, as well as a forecast of future emissions. An action plan with recommendations to reduce Greenhouse gas emissions in New Mexico is also being prepared (3).

The process of generating electricity is the single largest source of greenhouse gas emissions in the United States (34 percent) [4]. CO_2 emissions. The Desert Rock Energy Facility will contribute approximately 11,000,000 Tons/yr CO_2 emissions (5, 6).

Desert Rock is a new proposed power plant in the Four Corners area. Technology is now available to capture and store CO_2 emissions. Many of these technologies are easier and less expensive if integrated into the design and construction of the power plant, rather than added later as retrofits. Retrofitting generating facilities for Carbon Capture and Storage (CCS) is inherently more expensive than deploying CCS in new plants (7).

CO2 capture and storage involves capturing the CO2 arising from the combustion of fossil fuels, as in power generation, or from the preparation of fossil fuels, as in natural-gas processing. Capturing CO2 involves separating the CO2 from some other gases. For example in the exhaust gas of a power plant other gases would include nitrogen and water vapor. The CO2 must then be transported to a storage site where it will be stored away from the atmosphere for a long period of time. In order to have a significant effect on atmospheric concentrations of CO2, storage reservoirs would have to be large relative to annual emissions. (IPCC, 2001)

This mitigation option is for Desert Rock Energy Facility and any other proposed power plants to invest into CO_2 emissions control and capture technologies. Desert Rock is in a unique situation to set an example and take the lead in this emissions reduction field.

Desert Rock Energy LLC submitted a set of comments on the Four Corners Air Quality Task Force report during the public comment period including a discussion of CO2 emissions. The comments are located in an appendix at the end of the Power Plants section.

Benefits: Reduced CO_2 emissions
Tradeoffs: None
Burdens: CO_2 control technology is expensive. Burden would be on the power plant; however, there may be some funding for the innovative technologies that would be used.

II. Description of how to implement
A. Mandatory or voluntary
Voluntary

Differing Opinion: According to experts, Desert Rock, if built, would be the seventh largest source of greenhouse gas pollution in the Western United States. It is expected that Desert Rock will emit over 11million tons of carbon dioxide per year. Emission controls on carbon dioxide will most likely be required in the very near future. Carbon dioxide emission reduction technology should be mandatory on the Desert Rock facility.

B. Indicate the most appropriate agency(ies) to implement
Environmental Protection Agency (EPA) Region 9 Air Program
Navajo Nation Air Programs
Industry leadership

EPA Climate Protection Partnership is a possible or New Mexico's San Juan Voluntary Innovative Strategies for Today's Air Standards (VISTAS) are possible vehicles for this mitigation option.

III. Feasibility of the option
A. Technical: Technologies exist; many are in the research and development phase. Technological components are commercially ready in unrelated applications (7).

B. Environmental: Capturing and storing CO_2 emissions is difficult. Integrated systems have yet to be constructed at necessary scales. Feasibility question remains whether CO_2 could be stored without substantial leakage over time

C. Economic: Capturing and storing CO_2 emissions can be expensive.

IV. Background data and assumptions used
(1) Desert Rock Energy Project FACT SHEET #1, DEC 2004 (http://www.desertrockenergy.com/)
(2) AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)
(3) Climate Change Advisory Group (CCAG) homepage: http://www.nmclimatechange.us/index.cfm
(4) EPA Climate Protection Partnerships: http://www.epa.gov/cppd/other/energysupply.htm
(5) 4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10
(6) San Juan Generating Station has a total 1798 MW generation capacity, and emits approximately 13,097,000 Tons CO_2/yr. Approx 7,300 Tons CO_2 per MW generation capacity. San Juan Generating Station CO_2 rationing by MW is used as estimation for CO_2 emissions from Desert Rock Energy Facility. Based on this assumption, the CO_2 emissions from Desert Rock Energy Facility will be approximately 11,000,000 Tons/yr.
(7) Scientific American, September 2006 article, "What to do about Coal," pp. 68-75

V. Any uncertainty associated with the option High

<u>VI. Level of agreement within the work group for this mitigation option</u> To Be Determined

<u>VII. Cross-over issues to the other Task Force work groups</u> None

Mitigation Option: Federal Land Manager Mitigation Agreement with Desert Rock Energy Facility

I. Description of option

Background

Sithe Global Energy (Sithe) is proposing the Desert Rocky Energy Facility (DREF) on the Navajo Nation in northwestern New Mexico. The proposed facility would be within 300 km of 27 National Park Service units, nine of which are Class I areas, and six are U.S. Forest Service Class I areas. The proposed facility will have two 750 megawatt pulverized-coal boilers, and would be well-controlled for a coal-fired power plant. SO2 emissions would be controlled to 3,315 tons per year with Wet Limestone Scrubbers, and NOx emissions would be controlled to 3,315 tons per year with Low-NOx burners and Selective Catalytic Reduction. Despite these controls, the National Park Service and U.S. Forest Service have concluded that the emissions from DREF, absent mitigation measures, would have an adverse impact on visibility at four or more Class I areas in the region. There are also concerns with the emissions contributing to cumulative negative impacts in the region as a whole.

The permitting authority for the Desert Rock Energy Facility is the Environmental Protection Agency (EPA) Region 9, because the facility would be located on the Navajo Reservation, where neither the State of New Mexico (or Arizona) nor the Navajo Nation have permitting authority. For over two years, the National Park Service and the U.S. Forest Service worked closely with Sithe, EPA and tribal representatives to ensure the potential impact of the proposed facility were carefully analyzed. When it became evident that emissions from the facility could adversely impact visibility in several Class I areas, the energy company suggested mitigation measures intended to produce a net environmental improvement in the area, notwithstanding construction and operation of the DREF. Sithe and the federal land managers (FLMs) both sought to avoid a formal adverse impact determination that would jeopardize the issuance of the air quality permit. Negotiations ensued and resulted in an agreement in principle on substantive mitigation measures in April of 2006.

In July, 2006, EPA issued a proposed PSD permit for the facility but did not include the agreed-upon mitigation measures. EPA reasoned that mitigation measures should not be included as part of the permit absent a formal declaration of adverse impact by the FLM.
Both the National Park Service and the U.S. Forest Service have asked EPA to include the mitigation measures in the PSD permit. In the absence of the terms of the agreement in principle included as part of the final PSD permit, Task Force members are interested in ensuring the measures will be put in place to avoid adverse impacts to air quality related values in Class I areas and the region as a whole will be avoided throughout the life of the facility.

Sulfur Dioxide Mitigation

The following options outline the sulfur dioxide mitigation strategy for the DREF. The choice between Option A or Option B shall be made by Sithe or its assigns prior to the commencement of DREF plant operations.

Option A: For the purposes of mitigating potential air quality impacts, including potential visibility and acid deposition impacts, of the DREF at Class I and Class II air quality areas in the region potentially affected by DREF, Sithe[1] shall develop or cause to be developed a capital investment project or projects that generate Emission Reduction Credits from physical and/or operational changes that result in real emission reductions at one or more Electric Generating Units[2] (EGUs) within 300 km of the DREF and retire sulfur dioxide[3] Allowances in accordance with the following:

- The number of sulfur dioxide Emission Reduction Credits required for the respective calendar year shall be determined by DREF's actual sulfur dioxide emissions, in tons, plus 10%, measured as set forth in the next paragraph below.
- The amount of Emission Reduction Credits achieved would be determined by comparing the emission rate (in tons) during the year for which the reduction is claimed to a baseline emission rate. The baseline emission rate shall be the average emission rate (in tons per year) during the two-year period prior to any emission reduction taking place.
- Acceptable sulfur dioxide Emission Reduction Credits under this condition shall be allowances originating from facilities that were allocated sulfur dioxide Allowances under 40 CFR 73[4] and that are located within 300 km of the DREF facility.
- The vintage year of the Emission Reduction Credits shall correspond to the year that is being mitigated. Sithe shall retire the required Emission Reduction Credits by transferring an equivalent number of Allowances into account #XXX with the U.S. EPA Clean Air Markets Division[5]. Except for Sithe's purposes under Title IV, these retired Allowances can never be used by any source to meet any compliance requirements under the Clean Air Act, State Implementation Plan, Federal Implementation Plan, Best Available Retrofit Technology requirements, or to "net-out" of PSD. However, surplus Emission Reduction Credits could be used at the discretion of the holder of the credits.
- Sithe shall submit a report to the EPA Region 9 Administrator (or another party acceptable to the Federal Land Managers) no later than 30 days after the end of each calendar year which shall contain the amount of sulfur dioxide emitted; amount, facility, location of facility, vintage of Emission Reduction Credits retired; proof that Emission Reduction Credits/Allowances have been transferred into account #XXX; and any applicable serial or other identification associated with the retired Emission Reduction Credits/Allowances.

Due to the actual emission reductions obtained from nearby sources under this Option, the Federal Land Managers prefer this approach to mitigating DREF's air quality impacts.

Or,

Option B: For the purposes of mitigating potential air quality impacts, including potential visibility and acid deposition impacts, of the DREF at Class I and Class II air quality areas in the region potentially affected by DREF, Sithe shall obtain and retire sulfur dioxide "Mitigation Allowances" from one or more EGUs within 300 km of the DREF in accordance with the following:

- In addition to those Allowances required under Title IV, the required number of sulfur dioxide "Mitigation Allowances" for the respective calendar year shall equal DREF's actual total sulfur dioxide emissions, in tons.
- Acceptable sulfur dioxide "Mitigation Allowances" under this condition shall be from facilities that were allocated sulfur dioxide Allowances under 40 CFR 73 and that are located within 300 km of the DREF. However, the total annual cost of "Mitigation Allowances" purchased beyond those regular Allowances required by Title IV is not to exceed three million dollars[6]. Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining emission reductions, Sithe may obtain physical emission reductions at sources not granted allowances under 40 CFR 73.
- The vintage year of the "Mitigation Allowances" shall correspond to the year that is being mitigated. Sithe shall retire these "Mitigation Allowances" by transferring them into account #XXX with the U.S. EPA Clean Air Markets Division. These retired "Mitigation Allowances" beyond Title IV can never be used by any source to meet any compliance requirements under the Clean Air Act, State Implementation Plan, Federal Implementation Plan, Best Available Retrofit Technology requirements, or to "net-out" of PSD.

- Sithe shall submit a report to the EPA Region 9 Administrator (or another party subject to approval of the Federal Land Managers) no later than 30 days after the end of each calendar year which shall contain the amount of sulfur dioxide emitted from the DREF; amount, facility, location of facility, vintage of Allowances retired; proof that Allowances have been transferred into account #XXX; and any applicable serial or other identification associated with the retired Allowances.

Additional Air Quality Mitigation
If Sithe chooses Option A, it will contribute $300,000 annually toward environmental improvement projects that would benefit the area affected by emissions from DREF, including the Class I areas and the Navajo Nation. If Sithe chooses Option B, it will contribute toward environmental improvement projects an amount equal to the $3 million cap described under Option B above, minus the cost of the Mitigation Allowances, up to a maximum of $300,000. Appropriate projects will be determined jointly by the Federal Land Managers, Navajo Nation EPA, the Desert Rock Project Company and Diné Power Authority, and may include projects that would reduce or prevent air pollution or greenhouse gases, purchasing and retiring additional emission reduction credits or allowances, or other studies that would provide a foundation for air quality management programs. Up to 1/5 of the contributions can be dedicated to air quality management programs. The remaining contributions shall be used to support projects that mitigate greenhouse gas emissions or criteria pollutants impacts. The Desert Rock Project Company shall have the ability to bank the emission reduction credits achieved through these projects and be entitled to these credits to comply with future greenhouse gas emission mitigation programs. Mitigation and contributions toward environmental improvement projects shall not occur before operation of the Desert Rock Energy project begins.

And,

Sithe will reduce mercury emissions by a minimum of 80% on an annual average using the air pollution control technologies as proposed in the permit application, i.e. SCR, wet FGD, hydrated lime injection, and baghouse. In addition, Sithe will raise the mercury control efficiency to a minimum of 90% provided that the incremental cost effectiveness of the additional controls (such as activated carbon injection or other mercury control technologies) does not exceed $13,000/lb of incremental mercury removed. Compliance with this provision will be determined by installation and operation of an EPA-approved mercury monitoring and/or testing program. In operating periods when a minimum of 80% mercury control (or 90% as noted above) is not technically feasible due to extreme low mercury concentrations in the burned coal, Sithe will work with EPA to establish a stack mercury emission limit in lieu of a percent reduction, for the purposes of demonstrating compliance.

Examples of Mitigation Strategies

Example #1:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option A, Sithe would be required to reduce SO_2 emissions at another source (or sources) within 300 km by 3,300 tons. These credits can be used to meet the requirements of the acid rain program under Title IV of the Federal Clean Air Act provided that the physical and/or operational change occur on one or more EGUs.

Example #2:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option A, suppose Sithe reduces SO_2 emissions at another source (or sources) within 300 km by 4,000 tons. In this case, Sithe would have created 700 tons of surplus SO_2 Emission Reduction Credits that it may use as it sees fit.

Example #3:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option B, Sithe would purchase its “regular” 3,000 tons of Title IV Allowances from any source, anywhere, plus up to 3,000 tons of SO_2 “Mitigation Allowances” from another source (or sources) within 300 km, provided that the total cost of the “Mitigation Allowances” does not exceed $3 million (in 2006 dollars). If each “Mitigation Allowance” costs at least $1,000, Sithe would be done.

Example #4:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option B, Sithe would purchase its “regular” 3,000 tons of Title IV Allowances from one or more EGU sources. For the remaining 3000 SO2 “Mitigation Allowances”, Sithe may choose, as an option, to obtain 9000 NOx emission reduction credits from physical or operational changes of one or more NOx emission sources within 300 km.

Example #5:
Suppose Sithe obtains the necessary SO_2 reductions through a capital investment project (Option A), or purchases SO_2 Mitigation Allowances (Option B) at a cost of $2.7 million or less. Sithe would then contribute the maximum $300,000 to the environmental improvement fund because the total annual costs (allowances plus contribution) would be below the $3 million cap. On the other hand, if the mitigation allowances cost more than $2.7 million, Sithe would contribute the difference between the $3 million cap and the actual cost of the Mitigation Allowances (i.e., if allowance costs equal $2.9 million, the environmental improvement fund contribution would be $100,000).

Implementation
The clearest way for these measures to be implemented would be to include them in the PSD permit. Since EPA Region 9 is the permitting authority in this case, that agency would be responsible for including the measure in the permit. Absent including the measures in the permit, other ways of ensuring the mitigation measure will take place are being explored. The FLMs prefer that the mitigation measures be federally enforceable regardless of the mechanism ultimately used.

III. Feasibility of the option
By agreeing to the mitigation measures, Sithe has implicitly affirmed the feasibility of the measures. Incorporation into a permit is feasible for the permitting authority as long as the measure does not contradict any statutory or regulatory provision.

Background Data and Assumptions
The suggested mitigation measures are taken from the agreement-in-principle between Sithe Global Power and the FLMs. Estimated emissions from DREF come from the draft permit.

V. Any uncertainty associated with the option
The uncertainty in this option involves how stakeholders can be assured the measures will actually happen.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

Citations:
[1] References to Sithe include its subsidiary "Desert Rock Energy Company, LLC" which will be the owner of DREF (referred to herein as the Desert Rock Project Company).
[2] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining emission reductions, Sithe may obtain real emission reductions at sources other than EGUs.

[3] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining and tracking emission reductions, nitrogen oxides reductions may be substituted for sulfur dioxide reductions by a ratio of three tons of nitrogen oxides to one ton of sulfur dioxide.
[4] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining emission reductions, Sithe may obtain physical emission reductions at sources not granted allowances under 40 CFR 73.
[5] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining and tracking Emission Reduction Credits, Sithe may obtain real emission reductions at sources other than EGUs. Nitrogen oxides reductions may be substituted for sulfur dioxide reductions by a ratio of three tons of nitrogen oxides to one ton of sulfur dioxide.
[6] All costs referenced in this document are base-year 2006 dollars that will be adjusted for inflation by using the consumer price index.

FUTURE POWER PLANTS

Mitigation Option: Integrated Gasification Combined Cycle (IGCC)

I. Description of the mitigation option

Energy related projects in the Greater Four Corners Region (NM, CO, AZ, UT and WY) are expected to continue to grow at or above current rates. Population and related commerce growth in the 12 county local Four Corners Region (NM, CO, AZ, UT) grew at a brisk rate of 23.8% during the 1990s (1). Future electric power demand will require new power plants and transmission grid capacities. Alternative future "clean coal" power generation technologies such as, FutureGen, Integrated Gasification Combined Cycle (IGCC), and advanced fossil fuel power plants (with carbon capture and sequestration (CCS) technologies) and renewable energy facilities (e.g., wind farms, solar arrays, …) will be needed to accommodate this growth, as well as the increasing demand outside the Four Corners area. Given the size of the western coal reserve and its relatively inexpensive cost compared to natural gas, commercial IGCC power plants could potentially play a role in meeting the region's future "clean" power needs.

Overview: A power plant based on IGCCtechnology combines or integrates a coal gasification system (gasifier and gas clean-up systems) with a highly efficient combined cycle power generation system. There are a variety of coal gasification technologies in various stages of development that are designed to produce clean synthesis gas (syngas) from coal. The combined cycle unit includes a gas turbine set consisting of a compressor, burner and the gas turbine coupled with a heat recovery steam generator (HRSG). The steam generated in the HRSG, as well as any excess steam generated in the gasification process that is not used elsewhere in the system, is used to power a steam turbine. An IGCC unit has the potential to achieve similar environmental benefits and thermal performance as a natural gas fired combined cycle power generation unit. The use of relatively low cost coal as a feedstock is the one of the main advantages of coal-based power plants. The ability of an IGCC unit to use coal while generating lower air emissions than conventional coal technologies has lead to increased interest in the technology. While IGCC is a promising technology, it has not completely commercially developed. Two small 260 MWe IGCC plants, the Wabash River Plant in Indiana and the Polk Plant in Florida, have been operating for over a decade. Originally built as demonstration plants, reliability of the IGCC units has generally improved over time with gasifier capacity factors in the range of 80% demonstrated in a number of years (2). (Note: the Polk Power Station IGCC unit has only had one year of operation where the gasifier CF was greater than 80% and two years where the CF was near 80% in the 10+ years of operation.) Currently there are at least five separate permit applications for commercial size IGCC plants in the continental United States. Four of these applications are for plants exceeding 600 MWe nominal capacity.

The operation of the major chemical and mechanical process components of a typical coal based IGCC power plant can be summarized as follows (3):

- The gasifier produces syngas by partially oxidizing coal in presence of air or oxygen.
- The ash in the coal is converted to inert, glassy slag.
- The syngas produced from the gasifier is cooled.
- The syngas is cleaned to remove particles.
- The slag and other inert material are collected to be used to make some products or can be safely discarded in the landfill.
- The mercury is removed by passing syngas through the bed of activated carbon.
- The sulfur removed from the syngas is converted into elemental sulfur or sulfuric acid for sale to chemical or fertilizer companies.
- The clean syngas can either be burned in a combustion turbine/electric generator to produce electricity or used as a feedstock for other marketable chemical products.

- Steam produced in the HRSG from the hot combustion turbine exhaust, as well as additional steam that has been generated throughout the process, drives a steam turbine to produce additional electricity.
- The stream exhausted from the steam turbine is cooled and condensed back to water. The water is then pumped back into the steam generation cycle.

Benefits:

- For traditional pollutants such as nitrogen oxides (NOx), sulfur dioxide (SO_2), particulate matter (PM) and mercury (Hg), IGCC is lower polluting than the current generation of traditional coal-fired power plants. It is potentially as "clean" a NOx emitter (< 0.3 lb/MW-hr) as for NGCC plants (4).
- The removal of sulfur compounds, particulates and mercury is more efficient in an IGCC because the removal can take place before the gas is burned (fuel gas) instead of removing the compounds from the exhaust gases following combustion (flue gas).
- The water requirement for the IGCC process is approximately one-third less than that of a pulverized coal plant.
- Solid waste generation at an IGCC power plant is less than that of a PC plant.
- IGCC plants are more flexible in terms of fuel feedstock because they can utilize a variety of fuels, such as coal, biomass, and refinery by-products such as petroleum coke (petcoke). In general, IGCC units are designed to use only one type of coal (i.e. bituminous, sub-bituminous or lignite), but can handle a variety of coals from within the same coal type.
- The CO_2 emissions from an IGCC unit can be higher than from a conventional coal power plant (3). However, based on current technology, it is believed that capture of CO_2 emissions from IGCC plants would be more energy efficient than capture from a conventional coal fired power plant.
- IGCC plants operate at efficiencies of about 40% but have the potential to be as high as 45% (or higher if fuel cells are used). By comparison, conventional combustion-based power plants have efficiencies that range from about 33% to 43%.

Burdens (or deployment barriers):

- General lack of commercial-scale operating experience, especially at Four Corners altitudes.
- Doubts about plant financial viability without subsidies. IGCC has significantly higher capital costs, nominally approximately 20% or higher than the cost for conventional PC plants (Wayland, 2006).
- Low plant reliability, demonstration of commercial plant reliability and capacity factor remains a concern.
- Without carbon capture, an IGCC can have a higher carbon footprint compared to a conventional PC plant. However, the lower total gas flow, the higher percentage of CO_2 in the gas stream, combined with the high operating pressure of the gas stream, makes it easier to recover CO_2 from the syngas in IGCC power plants than from flue gas in conventional coal power plants, based on current technology.
- IGCC carbon capture and sequestration (CCS) technologies have not yet been demonstrated at commercial scale. However, once CCS is demonstrated, IGCC has a potential advantage in capturing and sequestrating CO_2 at lower costs for the reasons stated in the bullet above.

II. Description of how to implement

A. Mandatory or voluntary

Voluntary to look at IGCC as a future clean power generation option for future power plants in the Four Corners area.

B. Indicate the most appropriate agency(ies) to implement
Policy options for use of Integrated Gasification Combined Cycle Technology could be developed by Environmental Protection Agency (EPA), Department on Energy (DOE), State or Tribal Environmental Protection Agencies.

III. Feasibility of the option
A. Technical: There is some concern about the feasibility of IGCC power plants at high altitude, elevated temperatures and using western fuels. High altitudes and elevated temperatures lead to significant derations of the power output from the gas turbine portion of the IGCC unit. Turbine manufacturers are working on ways to overcome this altitude deration but, to-date, no solutions have been developed and/or demonstrated.

Carbon dioxide capture technology from IGCC units is still in its research and development phase. To be more cost competitive, a number of technology improvements will need to be made in IGCC plant design; including larger, higher pressure and lower cost quench gasifiers (6). In addition, new and improved gas turbines will be needed that enable air extraction across the operating range of ambient temperatures and with hydrogen firing (7).

Carbon capture and sequestration technologies have potential to substantially reduce carbon emissions into the atmosphere. However the given the current cost of carbon capture and sequestration technologies, it will not be viable solution without a carbon penalty. CO_2 sequestration is also a site-specific geological issue. Options to address this issue include:

- Locating the IGCC unit in an area suitable for geologic sequestration, EOR, EGR or ECBMR
- Pipe the captured CO_2 from an IGCC unit to an area suitable for geologic sequestration, EOR, EGR or ECBMR
- Gasify the coal close to an area suitable for geologic sequestration, EOR, EGR or ECBMR and then send the gas for the power production (although this option does not receive the efficiency benefits associated with a fully integrated IGCC unit).

Currently in the US there are two small IGCC plants, the Tampa Electric Polk Power Station in Florida and the Wabash River Coal Gasification Repowering Plant in Indiana, using coal to make electric power as the primary product. These plants were funded and built in the mid-1990s as demonstration plants by DOE. Recently, however, five companies have applied for and in few cases already received permits and at least five companies have announced plans or issued letters of intent to build and operate IGCC facilities in the US. American Electric Power is proposing to build two 629 MW power plants in Ohio and West Virginia – although the projects have been put on hold due to concerns over project cost escalation (as have several other utilities) (8). Xcel Energy is investigating building an IGCC plant with CO_2 capture and sequestration. Duke and Tampa Electric have received tax credits to help reduce the cost of building IGCC power plants under the Energy Policy Act of 2005.
B. Environmental: For traditional pollutants such as NOx, SO_2, PM and Hg, IGCC is inherently lower polluting than the current generation of traditional coal-fired power plants. There are a number of concerns related to the geologic sequestration of CO_2, whether or not the CO_2 is from an IGCC unit. These concerns include, but not limited to the following:

- How will geologic sequestration be permitted over the long-term, including demonstration studies and the duration of the sequestration permit (i.e. 5 year, life of facility, etc.)
- What measurement, monitoring and verification (MMV) techniques and requirements will be placed on the project
- How will the liability associated with the sequestered CO_2 be addressed
- How will the property rights associated with the sequestered CO_2 be addressed

- Will the injection of CO_2 into a deep saline aquifer prohibit the future use of water from that aquifer should in-land desalination prove to be cost-effective or necessary to address future water needs

C. Economic: IGCC has higher capital costs than conventional PC plants (9). Historically – and currently, concerns about operational reliability and costs presented issues of uncertainty for IGCC technology and impeded its deployment. IGCC can be a versatile technology and is capable of using a variety of feedstocks. In addition to various coal types, feedstocks can include petroleum coke, biomass and solid waste.

Along with electricity production, IGCC facilities, if designed to do so, can co-produce other commercially desirable products. Some of these products include steam, oxygen, hydrogen, fertilizer feed stocks and Fischer-Tropsch fuels (10).

There is not a consensus about the relative costs of carbon capture technology for various plants. General consensus is that, given current technology, it is less expensive to capture CO2 from IGCC plants than from any other coal-based plant, as well as NGCC plants (11). According to an MIT study, today the capital cost (in 1999 dollars?) of CO_2 capture and separation is $1730/kW, which will reduce to $1433/kW in 2012. The CO_2 capture and separation cost for a NGCC power plant is about $1120/kW today, which will reduce to $956/kW in 2012 (12). There are many uncertainties with regards to the costs of CCS.

The operational versatility noted above for IGCC technology may mitigate the risk of higher costs. In addition, under the Energy Policy Act of 2005, there are provisions for tax credits and a DOE Loan Guarantee Program to provide incentives to facilitate the deployment of IGCC technology.

IV. Background data and assumptions used:

(1) City of Farmington Draft Consolidated Plan, 2004, June

(2) Coal-Based IGCC Plants – Recent Operating Experience and Lessons Learned. Gasification Technologies Conference, Washington, DC (October 2006).

(3) Pioneering Gasification Plants (DOE): http://www.fe.doe.gov/programs/powersystems/gasification/gasificationpioneer.html

(4) Wayland, R.J., 2006, U.S. EPA's Clean Air Gasification Activities, Gasification Technologies Council, Winter Meeting January 26, Tucson, Arizona

(5) Blankinship, Steve. "Amid All the IGCC Talk, PC Remain the Go-To Guy." Power Engineering International.

(6) Revis, James, 2007, Clean Coal Technology Status: CO_2 Capture & Storage *Technology Briefing for COLORADO RURAL ELECTRIC ASSOCIATION, February 19*

(7) Wabash River IGCC Topical Report 2000 **-** www.fossil.energy.gov/programs/powersystems/publications/Clean_Coal_Topical_Reports/topical20.pdf

(8) American Electric Power permit application for proposed IGCC power plant in Great Bend, Ohio and Mountaineer, West Virginia. http://www.aep.com/about/igcc/technology.htm

(9) Technical Report on the Environmental Footprint and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, Fact Sheet: http://www.epa.gov/airmarkets/articles/IGCCfactsheet.html

(10) IGCC & CCS Background Document. 2006, State Clean Energy-Environment Technical Forum Integrated Gasification Combined Cycle (IGCC) Background and Technical Issues June 19

(11) Clayton, S.J., Stiegel, G.J., and Wimer, J.G., 2002, Gasification Technologies Product Team U.S. Department of EnergyU.S. DOE's Perspective on Long-Term Market Trends and R&D

Needs in Gasification 5th European Gasification Conference Gasification – The Clean Choice Noordwijk, The Netherlands April 8-10
(12) Herzog, Howard. “An Introduction to CO_2 Separation and Capture Technologies.” MIT Energy Laboratory (1999).

V. Any uncertainty associated with the option (Low, Medium, High):
Medium to High, particularly when coupled with CCS as both are developing technologies.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups: None at this time.

Mitigation Option: Carbon (CO_2) Capture and Sequestration (CCS)

I. Description of the mitigation option

Carbon Capture and Sequestration (CCS) generally consists of removing carbon in the form of CO_2 from either the fuel gas stream; syngas of an Integrated Gasification Combined Cycle (IGCC) power plant or the flue gas stream of other fossil fuel power plants (i.e. pulverized coal, including supercritical pulverized coal (SCPC) and ultra-super critical pulverized coal (USCPC), and natural gas (NGCC) units) compressing and transporting the CO_2 to the sequestration site and sequestering the CO_2. Sequestration can consist of either injecting the CO_2 into a deep saline aquifers or using the CO_2 for enhanced oil recovery (EOR), enhanced natural gas recovery (EGR) or enhanced coal bed methane recovery (ECBMR). Utilization of CCS in combination with other mitigation options such as alternative fuels, energy efficiency and renewal energy would mitigate the potential greenhouse gas (GHG)/climate change impacts of using fossil fuels for power generation.

Overview:

Currently, there are two generic types of CO_2 removal solvents available:

- Chemical absorbents (i.e. amines) that react with the acid gases and require heat to reverse the reactions and release the CO_2
- Physical absorbents (i.e. Selexol and Rectisol) that dissolve CO_2

Amines: Amines are organic compounds that contain nitrogen as the key atom. Structurally, amines resemble ammonia. The advantage of an amine CO_2 removal system is that it has a lower capital cost than any of the current physical solvent processes. The disadvantage is that an amine system uses large amounts of steam heat for solvent regeneration and energy to re-cool the amine, making it a less energy efficient process.

Selexol: Selexol is the trade name for a physical solvent that is a mixture dimethyl ethers of polyethylene glycol. In the Selexol process, the solvent dissolves the CO_2 from the gas stream at a relatively high pressure, generally in the range of 300 – 1,000 psia. The resulting rich solvent can then either be let down in pressure and/or steam stripped to release and recover the CO_2. The Selexol process requires less energy than amine-based processes as long as the operating pressure is above 300 psia. At lower pressures, the amount of CO_2 that is absorbed per volume of solvent drops to a level that generally favors the use of an amine system.

Rectisol: Rectisol is the trade name for a CO_2 removal process that uses chilled methanol. In the process, methanol at a temperature of approximately –40 °F absorbs the CO_2 from the gas stream at a relatively high pressure, generally in the range of 400 – 1,000 psia. The resulting rich solvent can then either be let down in pressure and/or steam stripped to release and recover the CO_2. While the methanol solvent is less expensive than the Selexol solvent, the Rectisol process is more complex, has a higher capital cost and requires costly refrigeration to maintain the low temperatures required. It does, however, provide for the most complete removal of CO_2.

Cryogenic coolers are also currently shown to capture CO2 from the combustion exhaust. The cost of CO2 capture is generally estimated as three fourth of the whole carbon capture, storage, transport, and sequestration system. Currently the average cost of carbon capture is about $150/ton by using current technology is high for carbon emission reduction purposes (1). In order to transport and sequester the CO_2, the gas must be compressed to 2000 psia or higher. Research is underway to find better technologies for carbon capture. Presently, the most likely identifiable options apart from absorbents for the carbon separation and capture are (1):

- Adsorption (Physical and Chemical)
- Low-temperature Distillation
- Gas separation Membranes
- Mineralization and Biomineralization

Benefits:

- CO_2 that would otherwise be emitted to the atmosphere is sequestered.
- If used for Enhanced Oil Recovery (EOR), Enhanced Gas Recovery (EGR) or Enhanced Coal Bed Methane Recovery (ECBMR), the CO_2 from power plants is put to beneficial use and could replace some or all of the natural CO_2 that is currently used for those purposes as well as recover fossil fuel.

Burdens (or deployment barriers):

- Currently there are no power plants in the world that perform CCS, so the integration of the power plant technology with the CCS technology has yet to be proven.
- The capital and O&M costs for CCS are significant and adversely impact the cost of electricity (COE). The cost of electricity will increase by 2.5 cents to 4 cents/Kwh if current carbon capture technologies are added to electrical generation(1).
- No large-scale tests of deep saline aquifer injection have been performed to-date. The Sleipner project in Norway's North Sea is the world's first commercial carbon dioxide capture and storage project(2). CO2 is extracted from gas production on Statoil's Sleipner West Field in the Norwegian North Sea. Started in 1996, it sequesters about 2800 tons of carbon dioxide each day and injects into Utsira sandstone formation (aquifer)(3).
- No environmental laws, rules or procedures are in place for CCS projects.

II. Description of how to implement

A. Mandatory or voluntary

Voluntary in the near term; mandatory as laws, rules and procedures are established.

B. Indicate the most appropriate agency(ies) to implement

Environmental Protection Agency (EPA), Department on Energy (DOE), State Environmental Protection Agencies.

III. Feasibility of the option

A. Technical:

IGCC

In IGCC power plants, CO_2 can be captured from the synthesis gas after the gasification process before it is mixed with air in a combustion turbine. The CO_2 is relatively concentrated (50 volume %) and at high pressure which provides the opportunity for lower cost for carbon capture (4).
While proven carbon capture technology is available for IGCC plants, there are currently no IGCC facilities in the world that capture, compress and sequester CO_2. Depending on the IGCC technology and the carbon capture technology used, it is estimated that carbon capture and compression could add 35 - 50% to the capital cost of the plant and the cost of electricity. These costs do not include the costs for installation of wells and/or pipelines for sequestration of the captured and compressed CO_2, both from a demonstration (pre-permitting) and ongoing operations perspective.

A number of IGCC technology vendors are working on improvements to their gasifiers that allow for easier CO_2 capture at reduced capital and O&M cost. In addition, a number of firms are working on improved CO_2 capture systems, with most efforts in the area of enhanced or advanced amine systems. It is too early in the development process to verify or quantify the potential cost and performance benefits of these new design efforts.

Another concern is the fact that there is currently no large combustion turbine commercially available that is capable of burning the hydrogen rich gas that would result from an IGCC plant with CCS.

SCPC/USCPC

While proven carbon capture technology is available for SCPC/USCPC plants (currently limited to amine systems), there are currently no SCPC/USCPC facilities in the world that perform CCS. Depending on the carbon capture technology used, it is estimated that carbon capture and compression could add 65 - 100% to the capital cost of the plant and the cost of electricity. These costs do not include the costs for installation of wells and/or pipelines for sequestration of the captured and compressed CO_2.

A number of projects are currently underway to try to improve the capture of CO_2 from SCPC/USCPC units in terms of removal efficiency and capital and O&M expenditures. Generally, these projects are targeting 90% capture of CO_2, although there is a general belief that the optimal/achievable reduction level will be less. EPRI and Alstom are working on a chilled ammonia (chemical absorbent) system. A 5 MW slipstream chilled ammonia pilot system will go into operation in Wisconsin in the fall of 2007. According to EPRI, the goal for the project is to reduce the cost for CO2 capture and compression by approximately 66% versus the cost of conventional amine systems. While the exact costs and efficiency gains of the chilled ammonia system are not known at this time, it is known that the system efficiency will decrease in warmer climates.

Babcock & Wilcox (B&W) is currently working on a design for a 500 MW oxygen fired, recirculating gas stream (oxy-fired) boiler for Sask Power in Canada. This unit would use oxygen from an air separation unit (ASU) instead of air for combustion. This use of oxygen means that less NOx is formed (approximately 65% less) in the combustion process and that the resulting flue gas is mainly CO_2 (up to approximately 80%). The flue gas stream, after removal of particulates, SO_2 and moisture, would be recirculated through the boiler, removing a portion (20 - 35%) of the CO_2 with each pass. B&W expects to start testing the design at their 30 MW Clean Environment Development Facility (CEDF) in Alliance, Ohio in June of 2007. Net power output before CCS from the 500 MW unit is expected to be on the order of 350 MW. Additional power will be required to compress and sequester the captured CO_2.

In addition, a number of vendors are working on enhanced/advanced amine systems that they believe will outperform current amine systems.

NGCC

While carbon capture technology is available for NGCC plants (currently limited to amine systems), there are currently no NGCC facilities in the world that perform CCS. Depending on the carbon capture technology used, it is estimated that carbon capture and compression could add 40 - 80% to the capital cost of the plant and the cost of electricity. These costs do not include the costs for installation of wells and/or pipelines for sequestration of the captured and compressed CO_2.

B. Environmental: There are currently no environmental laws, rules or procedures in place for CCS projects. Issues that need to be addressed include, but are not limited to:

- How will geologic sequestration be permitted over the long-term, including demonstration studies and the duration of the sequestration permit (i.e. 5 year, life of facility, etc.)
- What measurement, monitoring and verification (MMV) techniques and requirements will be placed on the project
- How will the liability associated with the sequestered CO_2 be addressed
- How will the property rights issues associated with the sequestered CO_2 be addressed
- Will the injection of CO_2 into a deep saline aquifer prohibit the future use of water from that aquifer should in-land desalination prove to be cost-effective or necessary to address future water needs

C. Economic: The capital and O&M impacts of CCS are significant and will result in substantial increases in the cost of electricity.

IV. Background data and assumptions used:

1) Carbon Capture Research. U.S. Department of Energy <http://www.fossil.energy.gov/programs/sequestration/capture/>
2)Carbon Capture and Sequestration Technologies, MIT. <http://sequestration.mit.edu/>
3) Carbon Dioxide storage prized. STATOIL. <http://www.statoil.com/statoilcom/SVG00990.NSF?OpenDatabase&artid=01A5A730136900A3412569B90069E947>
4) Carbon Sequestration. National Energy Technology Laboratory. <http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html>

V. Any uncertainty associated with the option (Low, Medium, High)

High, as the integration of power generation and CCS is a developing and undemonstrated technology and there are currently no laws, rules and procedures are established to address CCS.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups: None at this time.

Mitigation Option: Negotiated Agreements in Prevention of Significant Deterioration (PSD) Permits

I. Description of option

Summary of Option

Agreements regarding mitigation of air quality and air quality related value impacts negotiated between PSD permit applicants and parties other than the permitting authority should be incorporated into the PSD permit and made federally enforceable. If the other party is a federal land manager, there should not have to be a formal declaration of adverse impact before the agreement is made part of the permit.

Background

A primary goal of the PSD program is to protect air quality and air quality related values in areas that attain the National Ambient Air Quality Standards, specifically certain National Parks and Wilderness areas (i.e., "Class I" areas). If representatives of a proposed new source are willing to mitigate the predicted impacts of the new facility, then the permitting authority should honor this intent to reduce air pollution impacts at Class I areas by including mitigation measures in a PSD permit.

This issue arose in the context of federal land manager (FLM) review of the Desert Rock Energy Facility permit application. Federal land managers responsible for "Class I" areas are responsible for reviewing PSD permit applications for new sources to determine if that source would cause or contribute to an adverse impact on visibility or other air quality related values. In the immediate Four Corners area, Mesa Verde National Park and Wemminuche Wilderness Area are the closest Class I areas, and would be impacted the greatest by the Desert Rock Energy Facility. However, there are a total of 15 Class I areas that could be impacted by the facility.

Typically, FLMs address potential adverse impacts through consultation with the permit applicant and permitting authority before the permit is proposed, and before any formal adverse impact finding. When it becomes apparent through the modeling analysis that a facility *may* have an adverse impact, applicants are generally willing, and actually prefer, to discuss changes to address those adverse impacts, through tightening down the control technology, obtaining emission offsets, or other methods. State permitting agencies have generally incorporated the agreed-upon mitigation measures directly into the PSD permit, which as a practical matter, makes those agreements enforceable. This process allows for consultation in the case of suspected adverse impacts and avoids delays in permitting or denial of a permit, which may result from a formal finding of adverse impact.

The permitting authority for the Desert Rock Energy Facility is the Environmental Protection Agency (EPA) Region 9, because the facility would be located on the Navajo Reservation, where neither the State of New Mexico (or Arizona) nor the Navajo Nation have permitting authority. For over two years, the National Park Service and the U.S. Forest Service worked closely with Desert Rock representatives, EPA and tribal representatives to ensure the potential impact of the proposed facility were carefully analyzed. When it became evident that emissions from the facility could adversely impact visibility in several Class I areas, the energy company suggested mitigation measures intended to produce a net environmental improvement in the area, notwithstanding construction and operation of the Desert Rocky Energy Facility. Negotiations ensued and resulted in an agreement in principle on substantive mitigation measures in April of 2006. In July, 2006, EPA issued a proposed PSD permit for the facility but did not include the agreed-upon mitigation measures. EPA reasoned that mitigation measures should not be included as part of the permit absent a formal declaration of adverse impact by the FLM.

Without the terms of the agreement in principle included as part of the PSD permit, there is no mutually acceptable way to ensure the specific mitigation measures will be enforceable, and therefore, no assurance that adverse impacts to air quality related values in Class I areas will be avoided throughout the life of the facility.

It is unacceptable that the EPA, in July 2006, issued a proposed PSD permit for the facility but did not include the agreed upon visibility mitigation measures. The so called brown curtain of “regional haze” already present which blankets the Four Corners Area blocks visibility. Not only is it ugly, it indicates degradation of the air quality. Visibility mitigation must be enforceable; therefore, visibility measures must be included in the permitting of Desert Rock and any other future coal fired power plants in the Four Corners Area.

<u>II. Description of how to implement</u>

The permitting authority for a given facility would be responsible for including any agreed-upon mitigation measures into a PSD permit. Usually the permitting authority is the state agency responsible for air pollution control; in some cases, however, the EPA is the permitting authority.

Regarding the actual negotiation of any mitigation measures, information regarding the mitigation measure and its effects is exchanged in the permitting process. In some instances the applicant may supply additional information in the form of an air quality modeling analysis and/or control technology analysis to demonstrate to the FLM the effectiveness of the mitigation measures in reducing impacts to AQRVs at the Class I area(s) in question.

<u>III. Feasibility of the option</u>

By agreeing to a mitigation measure, a permit applicant has implicitly affirmed the feasibility of the measure. Incorporation into a permit is feasible for the permitting authority as long as the measure does not contradict any statutory or regulatory provision.

<u>IV. Background data and assumptions used</u>

The PSD program is created at 42 U.S.C. §§7470-7492; implementing regulations are codified at 40 C.F.R. §51.166 and 40 C.F.R. §52.21.

<u>V. Any uncertainty associated with the option</u>

No uncertainties known.

<u>VI. Level of agreement within the work group for this mitigation option</u>

To Be Determined

<u>VII. Cross-over issues to the other Task Force work groups</u>

None

Mitigation Option: Clean Coal Technology Public Education Program

<u>I. Description of the mitigation option</u>

The goal of this option is to educate all stakeholders, particularly the wider public, as to the cost/benefits of the latest clean coal technology during the permitting process for new coal based power generation facilities in the Four Corners. The public who then participates in the hearings and other steps of the permitting process, would be educated and know the pros and cons of the various technological options available to those proposing the project.

According to the Department of Energy, coal will continue indefinitely to be one of the least expensive sources of electric power in the United States. The Four Corners region has abundant coal resources and many stakeholders who wish to capitalize on that abundance to produce energy, jobs and revenue. Technologies for transforming coal to energy vary enormously in cost, and pollution, including release of global warming gases. Research into improved (cleaner) technologies continues, see President Bush's new commitment to the Clean Coal Power Initiative as one example. The public in the Four Corners area needs to be informed and frequently updated as to the status of research and testing in clean coal technology so they can ask educated questions and make educated political decisions and/or demands on policy-makers in the agencies permitting power generation installations in the Four Corners area. This mitigation option lays out a plan for the on-going education of Four Corners stakeholders with regard to the latest, cleanest, safest technologies for converting our generous resource into energy.

This option would require the primary permitting agency for a proposed project to designate early in the process a non-political 'clean coal technology scientist/advocate' whose responsibility it would be to prepare documentation in layman's terms on the latest research and feasibility of clean coal technology and where the proposed technology stands in relation to the current ideal. This individual would make presentations at hearings, be available by phone/internet for consultation with stakeholders, including the media, submit factual information pieces to the Four Corners media on clean coal technology, speak at community meetings, etc. In other words, the scientist/advocate would design and conduct an extensive public relations campaign to education the public during the permitting process.

Many institutions, including the Department of Energy, and educational institutions, conduct research in clean coal technology on an ongoing basis and NGOs like San Juan Citizens Alliance make themselves experts on the issues and could be called upon to educate the public at any given point. The obstacle here is how to ensure that the latest knowledge reaches the lay public when they can use it during the permitting process of new coal-based power plants and/or updates of older units. One way is to tie public education into the EPA permitting process. (Other ideas are welcome.) This option places an additional burden on the EPA in time, energy and cost and therefore indirectly on those proposing the new or updated power plants on to whom the additional costs of this step would be passed.

Participation of an educated public in the permitting process will lead to better long-term decision-making for the Four Corners area.

<u>II. Description of how to implement</u>

A. Mandatory or voluntary:
Mandatory

B. Indicate the most appropriate agency(ies) to implement:

The lead permitting agency, typically the EPA. The Department of Energy might be another appropriate agency; however, it is hard to envision how they could be motivated enough to know when and where their expertise is needed if not tied to the permitting process.

EPA is strongly encouraging companies proposing to build to power plants to meet with the local citizens in nearby communities and regional areas to discuss their plans including their projected emissions if the facility has been announced. In addition, if they are constructing near a non-attainment area for any pollutant, EPA believes it is important to meet with local air planning officials in the non-attainment area. The companies need to be willing to lay everything on the table with respect to technology, emissions, and comparisons to other similar facilities nationwide. The companies are better off actually doing these types of meetings before they even send in the permit application. Oftentimes, people are not opposed to a new cleaner EGU, but they want something done about those older existing units in the area. This hopefully will help educate the community on what the company would like to construct.

Remember once the permitting application arrives and the State proposes the permit for public comment.....some State regulatory requirements may require them to treat any meeting where comments are made about the facility's proposed permit and technology into the public record. Therefore, it would be encouraged that any meetings with the community to occur prior to the permit being public noticed.

Another option for sponsoring a Clean Coal meeting in the 4 Corners area is to invite speakers from Dept. of Energy, EPA, National Labs doing coal related work, and State permitting officials. It would also be okay to invite independent experts. Obviously, the issue becomes funding for such a meeting. Generally, a DOE and/or EPA rep will not cost you anything. Many technology vendors know the clean coal technology in depth and would participate.

Another option is to talk to state Air Quality Bureau chief about applying for special projects funds from EPA to host such an event in the future. It is not certain what type of funds DOE may have available, but they may have funding for such a meeting as well. Another option is for a company to fund as part of an enforcement settlement agreement, or for a consortium of the mining companies and power utilities to fund the meeting location, but the State to do all of the planning and agenda development for the meeting.

It would be strongly encouraged that the state environment department go through the actual permitting process at any meeting clearly showing in a process flowchart the specific points for public comment opportunities since it would be the state process that they would be following. The state environment department also needs to educate the public on the types of comments that actually are considered valid or significant comments.....(examples are great) versus the general "not in my backyard" comments.

Options for on funding, implementation, and a CCT public educational program within existing state PSD permitting programs:

- **Establish a federal/state agency MOU**: A memorandum of understanding (MOU) would provide a mechanism for CCT public information transfer during the PSD permit application. It could facilitate the selection of an independent engineer/ scientist on clean coal technology from nearby leading universities such as Colorado School of Mines or from independent national labs such as National Energy Technology Laboratory or from reputable CCT research non-for profit scientific institution such as Union of Concerned Scientists. The engineer/scientist would provide the public with status on CCT research/demonstration/commercialization as well as comparative advantages or disadvantages of these technologies with the proposed power plant technology (e.g., SCPC plant).

- **Develop and maintain a CCT education/information transfer web-portal**: New commercial power generation technological advancement occur over a relatively long time frame. An easily accessible and updatable source of CCT information and educational material can be provided through a web portal. Argonne has developed a variety of energy web portals, many with public outreach and some with educational elements (http://ocsenergy.anl.gov/, http://www.onlakepartners.org/). A web based outreach platform can provide CCT educational material on demand in layperson language and can provide public outreach tools for more informed and effective public involvement. Advancements in the clean coal technology could be updated on a regular basis. The state permitting agency could assume web-portal maintenance with an option for independent oversight and feedback from CCT experts. These experts (an engineer/scientist) can be retained to further support these efforts in person at public meetings during breakout public CCT education sessions.

III. Feasibility of the option

A. Technical:
Feasible, these people exist in the Four Corners area; Bill Green is an example of one. The Department of Energy undoubtedly could recommend local or regional experts.

B. Environmental:
Not relevant, no impact

C. Economic:
Retaining such a scientist/advocate will cost money but the reasonable expenses for this individual could be passed by the permitting agency to the organizers of the proposed power generation facility

This may require a regulatory and fee changes by state agencies......include a requirement for such a meeting in the State rules including a fee requirement for the permit applicant to fund the meeting location/facility to host such a meeting in the Regional area of the proposed facility. It would need to be researched and discussed to ensure that it's not prohibited by the CAA.

The ideas for funding of clean coal technology education program (within existing state PSD permitting programs):

- To implement such an effective clean coal technology education program a funding mechanism needs to be worked out between states and EPA. Options include but are not limited to:
    - The permitting fee for the power plan can be increased in order to pay for the the public education outreach program (e.g., web-portal and/or CCT expert).
    - Some non-for profit foundation involved in public education can be contacted to obtain a grant to build the webportal as well as pay for the compensation to experts/scientists.
    - It may be possible to find independent experts/scientists who will be able to provide their time for free for public good but there will still be a need of compensation for travel and lodging.

D. Political:
There is likely to be political resistance to spending additional dollars in this way. Additionally, the effort to educate the public on clean coal technology should be on ongoing effort, not dependent on proposal of power plants; however, it is difficult to figure out how to tie such an independent effort to the motivation and funding that it would take to get it to actually happen.

IV. Background data and assumptions used

Assumptions:

1. Coal continues to be abundant in the Four Corners area and in demand in power generation facilities
2. Stakeholders continue to desire to construct power generation facilities in the Four Corners area using coal, as opposed to transporting it out to other areas for use.
3. A standardized cost-effective perfectly clean technology for use of coal in power generation is years away.

V. Any uncertainty associated with the option (Low, Medium, High)

The only uncertainty that exists involves the degree of success the scientist/advocate would have in educating the public given the apathy sometimes exhibited by the public around these issues

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other Task Force work groups

Mitigation Option: Utility-Scale Photovoltaic Plants

I. Description of the mitigation option

Future Large-scale photovoltaic power plants (solar energy plants) could be built to accommodate future energy demands and offset some of the current coal-based coal fired power demands

Large-scale Photovoltaic power plants would consist of many PV arrays working together. PV electricity generation does not consume fuel and produces no air or water pollution.

The Electric Power Research Institute (EPRI) announced in July 2007 the beginning of a new project to study the feasibility of concentrating solar power in New Mexico. Unlike conventional flat-plate solar or photovoltaic panels, concentrating solar power (CSP) uses reflectors to concentrate the heat and generate electricity more efficiently. There are four utility-sized CSP plants in the U.S. today; one in Nevada and three in California. Initiated by New Mexico utility PNM and with subsequent interest from other regional utilities, the project will be directed and managed by EPRI. PNM has expressed interest in building a CSP plant in New Mexico by 2010. The feasibility study for a power plant of the 50-500 megawatt (MW) size range is expected to be finished by the end of 2007. The Four Corners area is one of the best areas for solar energy production in the United States and would be an ideal location for a new solar energy plant. For example, in Farmington, NM a flat-plate collector on a fixed-mount facing south at a fixed tilt equal to latitude, sees an avg. of 6.3 hours of full sun. The solar plant could help New Mexico meet renewable energy portfolio standards. San Juan County also has a renewable energy school focusing on solar energy system design and installation. The plant could potentially be an educational/technical resource for the college.

Benefits:

- Utilities can build PV plants much more quickly than they can build conventional fossil or nuclear power plants, because PV arrays are fairly easy to install and connect
- Unlike conventional power plants, modular PV plants can be expanded incrementally as demand increases
- Utilities can build PV power plants where they're most needed in the grid, because siting PV arrays is usually much easier than siting a conventional power plant
- Solar energy is clean energy and uses the sun for fuel.

Tradeoffs:
Burdens:

- Photovoltaic systems produce power only during daylight hours, and their output thus can vary with the weather. Utility planners must therefore treat a PV power plant differently than they would treat a conventional plant.
- Using current utility accounting practices, PV-generated electricity still costs more than electricity generated by conventional plants in most places, and regulatory agencies require most utilities to supply the lowest-cost electricity

II. Description of how to implement

A. Mandatory or voluntary

Mandatory (could be added as part of Renewable Energy Portfolio system)

May become more cost effective and implemented voluntarily as the technology continues to mature and power generation stakeholders see economic advantages to solar power.

B. Indicate the most appropriate agency(ies) to implement

State and Federal Governments can pass legislation requiring larger Renewable Energy Portfolios

III. Feasibility of the option
A. Technical –
PV Technology is available and technically feasible

B. Environmental –
PV systems have little adverse environmental impact

C. Economic –
Cost of PV systems to generate power is still more expensive than conventional fossil-fuels

DOE, the Electric Power Research Institute, and several utilities have formed a joint venture called *Photovoltaics for Utility-Scale Applications* (PVUSA). This project operates three pilot test stations in different parts of the country for utility-scale PV systems. The pilot projects allow utilities to experiment with newly developing PV technologies with little financial risk.

IV. Background data and assumptions used

1. DOE Energy Efficiency and Renewable Energy, Solar Energy Technologies Program
http://www1.eere.energy.gov/solar/utility_scale.html

2. PVUSA Solar: a Renewable Ventures Project, http://www.pvusasolar.com/

V. Any uncertainty associated with the option:
VI. Level of agreement within the work group for this mitigation option: To Be Determined.
VII. Cross-over issues to the other Task Force work groups
Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

Mitigation Option: Biomass Power Generation

I. Description of the mitigation option

Power Generation using biomass fuels can potentially reduce net CO2 emissions and other criteria pollutants from 4 Corners area power generation if displacing traditional coal-fired generation and is an option for future power plants in the area. Power from biomass is a proven commercial electricity generation option in the United States. With about 9,733 megawatts (MW) in 2002 of installed capacity, biomass is the single largest source of non-hydro renewable electricity. [1, 2]

Biomass used for energy purposes includes: Leftover materials from the wood products industry, Wood residues from municipalities and industry, Forest debris and thinnings, Agricultural residues, Fast-growing trees and crops, Animal manures. [2]

An aggressive Renewable Portfolio Standard was set in the 2007 NM legislative session. It includes 20% of power generation from renewables by 2020 (for large utilities) and 10% by 2020 (for rural electric cooperatives).
Biomass may be a necessary part of power generation to meet these standards.

In addition a 2005 executive order outlined Greenhouse Gas Emission Reduction Targets. These included reductions of NM Greenhouse gases to 2000 levels by 2012. Biomass power generation may be an alternative source of energy that can offset some of the CO2 emissions from fossil fuel-based combustion.

Benefits

Biomass combustion to produce electricity generates negligible Sulfur Dioxide and it has been shown to produce less Nitrogen Oxide emissions than coal-fired combustion. CO2 is absorbed during biomass growth cycle in photosynthesis and then released during combustion, so the direct combustion of the biomass feedstock can be considered to have a net 0 effect on CO2 emissions. If the biomass fuel can be planted, matured, and harvested in shorter periods of time compare to the natural growth plants then the recycling of CO2 in the environment can be reduced to close to one – third.

Other benefits include rural economic growth, increased national energy security, and using waste products that would otherwise have to be disposed. Using biomass fuel to generate electricity will reduce the greenhouse gas methane in the environment because if discarded in the landfill, the decomposition of biomass fuel generates methane.

Tradeoffs

- Land required for growing biomass.
- Higher nitrogen content of biomass fuel can contribute to higher NOx emission such as in the case of fertilizer used to grow biomass fuel.
- N2O emissions from fertilizer to grow biomass, if used.
- Energy emissions to grow, collect, and transport biomass fuel to plant
- Vehicle and dust emissions from transport trucks
- Energy emissions to dispose of waste
- The particulate emission from the biomass power generating power plant is a real concern. However the particulate emission can be controlled using readily available PM control technologies.

Burdens

For biomass to be economical as a fuel for electricity, the source of biomass must be located near to where it is used for power generation. This reduces transportation costs — the preferred system has transportation distances less than 100 miles.[3]

II. Description of how to implement

A. Mandatory or voluntary

Voluntary. Biomass may offset some of the coal based power generation.
May be necessary under new Renewable Portfolio Standard requirements for New Mexico & Colorado

B. Indicate the most appropriate agency(ies) to implement

Industry Research and Development, State and Federal Policy Support

III. Feasibility of the option

A. Technical – Biomass power generation is a proven commercial technology. Co-firing with fossil fuels may be the most feasible option at this time

B. Environmental – Biomass power generation has some significant advantages over fossil-fuel power generation. As demonstrated by some of the public hearings and objections to a new 35-megawatt plant, proposed to be built in Estancia, NM by Western Water and Power Production LLC., biomass may be a challenging technology to implement.

C. Economic –

A typical coal-fueled power plant produces power for about $0.023/kilowatt-hour (kWh). Cofiring inexpensive biomass fuels can reduce this cost to $0.021/kWh, while the cost of generation would be increased if biomass fuels were obtained at prices at or above the power plant's coal prices. In today's direct-fired biomass power plants, generation costs are about $0.09/kWh. In the future, advanced technologies such as gasification-based systems could generate power for as little as $0.05/kWh. For comparison, a new combined-cycle power plant using natural gas can generate electricity for about $0.04-$0.05/kWh at fall 2000 gas prices.[3]

IV. Background data and assumptions used

1. US DOE Energy Efficiency and Renewable Energy, Biomass Program
http://www1.eere.energy.gov/biomass/technologies.html

2. EIA RENEWABLE ENERGY 2002,
http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/table5.html]

3. US DOE Energy Efficiency and Renewable Energy, State Energy Alternatives
http://www.eere.energy.gov/states/alternatives/biomass.cfm

4. Electricity From: Biomass
http://powerscorecard.org/tech_detail.cfm?resource_id=1

V. Any uncertainty associated with the option: High.

VI. Level of agreement within the work group for this mitigation option: To Be Determined.

VII. Cross-over issues to the other Task Force work groups

Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

Mitigation Option: Bioenergy Center

I. Description of the mitigation option

Sunflower Electric Power Cooperative is planning a bio-energy center adjacent to their coal fired electric plant in rural Kansas[1].Three new 700 MW units are planned to supplement the existing 360 MW unit. The bioenergy center promises some CO2 mitigation along with energy efficient and low pollution auxiliary business enterprises. The bioenergy center concept involves a feedlot, dairy, anaerobic digester, algae reactor, ethanol plant, biodiesel plant, and the coal plant. Methane, electricity, ethanol, and biodiesel will be produced. The wastes (water, manure, biogas, nitrogen, phosphorus, flue gas, glycerol, CO2, wet distiller's grain, and ammonia) are used for inputs for the processes, rather than being discarded.

The anaerobic digester processes manure to produce methane to power the ethanol plant. The algae reactor consumes CO2 from the coal plant flue gas, and nitrogen and phosphorus from the anaerobic digester. The reactor then produces oil-rich protein for biodiesel production, with the residue used for livestock feed. The ethanol plant will consume corn and grain sorghum, and produce wet-distillers grain for livestock feed.

Locally, there could be variations on this theme. Excess corn fodder biomass, not fed to livestock, could be burned in the power plant. Only the grain is useful in ethanol production with current technology. Livestock could be omitted and the ethanol plant powered with natural gas.

Benefits: Any burned biomass has close to zero net effect on CO2 emissions from the coal fired power plant. Energy efficient businesses produce ethanol and biodiesel for sale. Local economic growth is enhanced, with increased national energy independence. Waste products are recycled that would otherwise have to be disposed.

Tradeoffs:
Land is needed to grow grain crops
Nitrate run-off from needed fertilizer
Ancillary energy usage, and lowering of CO2 net efficiency, to cultivate, harvest, and transport the crop, and remove waste products

II. Description of how to implement

A. Mandatory or voluntary: Voluntary.
It should be more feasible to plan such an adjunct facility at the proposed Desert Rock Power Plant, rather than at the existing power plants. Livestock and grain crops could be expanded at the NAPI, resulting in short transportation distances. Sithe Global is required to provide financing for local environmentally beneficial projects as an offset for tax benefits. This could help fund the feasibility studies for this project and a portion of the construction costs.

B. Indicate the most appropriate agency(ies) to implement
Navajo Nation, San Juan County, State of New Mexico economic development departments

III. Feasibility of the option

A. Technical – Co-firing biomass in coal plants is proven technology. Ethanol plants are being constructed at a rapid pace. There is a local construction company with extensive experience with ethanol plants. Each bio-energy component has been commercialized to some degree, but the challenge is the integration of these components in an energy center.

B. Environmental – VOC emission output from an ethanol plant could be mitigated by vapor capture routed to the power plant, or to a thermal oxidizer. The thermal oxidizer could accommodate vapors from the biodiesel plant. A portion of the power plant and thermal oxidizer CO_2 emissions would be mitigated by the algae reactor. Expanded feedlot activities have associated groundwater, ozone layer (methane), and odor impacts.

C. Economic – Detailed economic modeling is needed along with the engineering studies to provide input to a viable business plan. A renewable energy project should attract grant money and gain tax benefits. Labor infrastructure at the Desert Rock construction site could be leveraged to construct, then operate the bio-center.

IV. Background data and assumptions used

1. "Farming for Energy" Sunflower Electric's Bioenergy Center in Kansas – EnergyBiz Magazine, Jan./Feb. 2007 -- www.energycentral.com

2. Kansas Technology Enterprise Corporation -- http://www.ktec.com/index_Flash.htm

3. Four Corners Air Quality Task Force Mitigation Option "Biomass Power Generation"

V. Any uncertainty associated with the option (Low, Medium, High) High

VI. Level of agreement within the work group for this mitigation option To be discussed.

VII. Cross-over issues to the other Task Force work groups

Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

Mitigation Option: Nuclear Option

I. Description of the mitigation option

Nuclear reactor power generation should be considered as a mitigation option. We should not assume that it is too politically controversial for consideration. The mitigation options would lack balance if the taskforce were not to consider a future nuclear power plant. Such a plant would have virtually zero air emissions and global warming impact.

The U.S. Nuclear Regulatory Commission is adding staff to consider up to 30 nuclear units in fiscal 2008. This was motivated by the Energy Policy Act of 2005, which has invigorated the power industry to come forward with new plans. A new NRC office has been created solely for licensing and oversight of new reactor activities, with a current staff of 240. Many of these units will be in the south and southeast, where utilities have prior nuclear experience. NRC has streamlined their processes so standard design certifications will be approved, and the safety design hurdle will not be raised continually. Many of these applications will be active pump/valve cooling designs that meet the stringent safety requirements of standard design certifications.

These designs include the GE AWBR (Advanced Boiler Water Reactor), the Areva EPR (Evolutionary Power Reactor), and the Mitsubishi advanced pressurized water reactor. Bechtel is working on standard, pre-engineered modular designs, so that units can be replicated quickly and cost effectively. Construction time is approximately four to five years. If fifteen units were to be built from now until 2020, there would be a need for 30,000 new high-paying craft jobs. Several utilities are committing to these designs because of the certainty they will be completed on schedule with low risk financing, and their operating experience at similar plants.

There is promise for a family of passive cooling reactors, where gravity/density differences provide equivalent convection cooling protection to electrically powered valves and pumps. These designs would be simpler and less expensive than current active pump designs. Much design work has been done, although there is not currently such a unit in operation. General Electric is offering its ESBWR (Economically Simplified Boiling Water Reactor) and Westinghouse its AP1000, an advanced passive reactor. TVA and Entergy are considering use of this technology. Plants of this type will be among those soon licensed by the NRC.

Nuclear plants have lower maintenance costs (about 1.7 cents per kwh, v.s. 3 - 5 cents for a fossil fuel units). Operating experience has advanced greatly over the 30 years since Three Mile Island, with plants running at 90% capacity -- up from 70% in the 1970s.

Opposition will come from perceived plant safety and spent fuel issues. Regional storage of spent fuel already exists in New Mexico. It is likely that Yucca Mountain will be licensed for long term storage. New Mexico should participate in research for the safe long term storage of spent nuclear fuel. There is strong congressional and public recognition that nuclear power generation should be part of the energy portfolio, along with increased renewables, to address climate change. There is also a 20-30% group that opposes both existing and future nuclear power generation. This level of opposition would also be expected in New Mexico, and must be considered in any political process to license a nuclear plant locally. Worldwide, especially in China and India, there is a very active nuclear buildout in progress. Nuclear power generation is actively expanding worldwide, and about to in the United States.

A realistic approach would keep our options open politically, while closely monitoring the re-emergence of the nuclear industry in the United States over the next 5 – 10 years. We should especially follow the operating experience of the new passive cooling reactors which should be on-line in less than ten years. New Mexico is already in an area of low seismic activity. The additional safety advantage of a passive reactor design should lower public opposition significantly. Much of the anticipated surge of nuclear construction is by existing utilities that already operate conventional nuclear plants. It makes economic sense for many of them to continue in this direction. That argument does not hold in New Mexico, and we should embrace the construction of one or more passive nuclear power reactors as this technology matures.

We would expand our use of local coal reserves with the new Desert Rock power plant, and enjoy very low air emissions from that plant, except for the increased carbon footprint. Longer term (10 – 20 years), as power needs increase, we should consider a passive reactor nuclear plant instead of another coal fired plant. Some existing local coal fired units may approach the end of their design life and be retired. That retired power could be replaced by nuclear generation, with zero air emissions and carbon footprint.

A nuclear building program in the Four Corners would greatly enhance the growth of a local and regional high technology professional and vocational workforce. San Juan College would step up with new programs to educate the vocational workforce needed to build and operate a nuclear plant. The college should also benefit from creative financing support similar to that proposed for Desert Rock. The Four Corners and New Mexico would be recognized as an energy focal point in the U.S., with an exceptional balance of conventional, renewable, and nuclear energy generation, along with our strong base in oil/gas production.

Benefits: Zero air emissions impact; No carbon footprint; Cost effective electricity generation; Foster high technology educational and employment basis in the Four Corners; Proximity to current New Mexico and future Nevada spent fuel storage site.

Tradeoffs: Minority negative public opinion related to plant safety and spent fuel containment.

Differing Opinion: While it may be true that nuclear power plants have almost no carbon dioxide emissions (except in construction and in mining, processing and supplying the uranium fuel) and low global warming impact, there are other enormous liabilities which make them, in my opinion, the least desirable alternative to replace fossil fuel-fired power plants.

The availability of fissionable uranium (U-235) is not discussed. The supply will be quite limited, especially if the rate of usage increases significantly. One proposed solution, going to breeder reactor technology, would involve transport of radioactive materials to and from reprocessing plants, entailing enormous problems of safety and security.

The stated maintenance cost of 1.7 cents per Kwh for nuclear plants is deceptive. In all likelihood it does not include the cost of decommissioning the facility at the end of its useful life, nor the totally unknown cost of eventual "permanent" storage of the radioactive waste products. It also does not include any portion of the massive and continuing federal subsidies for nuclear R&D ($145 billion between 1947 and 1998 according to one source).

The issue of permanent storage of radioactive wastes (spent fuel) is not adequately discussed. The federal government and the nuclear industry have had half a century to develop permanent storage facilities; it seems they are no closer to a solution than when they started. Yucca Mountain is not close to viable, the latest blow being a federal court decision upholding the Nevada State Water Engineer's authority to deny the federal government's use of groundwater at the site. Even if a permanent storage facility is eventually developed, there is a major moral issue. I do not believe we have the right to impose an almost perpetual guardianship role on future generations (8,000 generations if the estimate of a 200,000 year storage time for plutonium wastes is accurate).

<u>II. Description of how to implement</u>
A. Mandatory or voluntary
B. Indicate the most appropriate agency(ies) to implement

<u>III. Feasibility of the option</u>
A. Technical –
B. Environmental –
We would expand our use of local coal reserves with the new Desert Rock power plant, and enjoy very low air emissions from that plant, except for the increased carbon footprint. Longer term (10 – 20 years), as power needs increase, we should consider a passive reactor nuclear plant instead of another coal fired plant. Some existing local coal fired units may approach the end of their design life and be retired. That retired power could be replaced by nuclear generation, with zero air emissions and carbon footprint.
C. Economic –
Nuclear plants have lower maintenance costs (about 1.7 cents per kwh, v.s. 3 - 5 cents for a fossil fuel units). Operating experience has advanced greatly over the 30 years since Three Mile Island, with plants running at 90% capacity -- up from 70% in the 1970s.

<u>IV. Background data and assumptions used:</u>
Reference: Energybiz magazine Vol. 4, Issue 3 (May 07, June 07) "Agency Gets Ready for Nuclear Renaissance" -- "Repackaging the Nuclear Option" -- "GE Gears Up." Vol. 4, Issue 4 (July 07, August 07) “Bechtel sees Nuclear Surge” and “The Nuclear Balance Sheet.”

<u>V. Any uncertainty associated with the option</u>: TBD
<u>VI. Level of agreement within the work group for this mitigation option</u>: To Be Determined.
<u>VII. Cross-over issues to the other Task Force work groups:</u>
Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

OVERARCHING: POLICY

Mitigation Option: Reorganization of EPA Regions

I. Description of the mitigation option

The Four Corners geographic area is under the jurisdiction of three different regions of the Environmental Protection Agency: Colorado and Utah are in Region 8, headquartered in Denver; New Mexico is in Region 6, headquartered in Dallas; and Arizona (and the Navajo Nation, which is in both Arizona and New Mexico) is in Region 9, headquartered in San Francisco.

Due to the abundance of coal and oil and gas in the San Juan Basin energy development in the area is likely to continue. It is becoming increasingly well-documented that the majority of the pollution experienced in the Four Corners area is coming from coal-fired power plants on or near reservation lands in New Mexico as well as oil and gas development throughout the region. The EPA staff engaged in addressing environmental impacts from oil and gas development, and responsible for actually permitting or overseeing permitting of stationary sources (power plants) needs to be located where the pollution is happening and be responsible to the recipients of that pollution as well as to hold its generators accountable.

A permanent EPA human presence within the area of energy development and pollution would sensitize EPA personnel to the issues within the Four Corners area. Creating an interregional office of the EPA with jurisdictional authority in order to include within a single jurisdiction the pollution generating sources and the public lands and communities they impact would improve EPA effectiveness in oversight and permit processing by facilitating communication and focusing feedback.

II. Description of how to implement

Create a permanent inter-region office within the EPA chartered to focus on, and located in, the Four Corners region. The office would assume all regional duties with respect to the Four Corners area, and have responsibility for overseeing state and tribal permitting, permitting stationary sources in the absence of state or tribal permitting, and any activities relating to oil and gas development currently performed by the various regions.

III. Feasibility of the Option

EPA Headquarters, as well as the three regions involved, would need to approve this option. The states and tribes would need to support this option as well.

IV. Background data and assumptions

The statement by Colleen McKaughan of Region 9 to the Durango Herald epitomizes our perception of the sensitivity of Region 9 personnel to the issues in the Four Corners region. As quoted in the Durango Herald on September 15, 2006, Ms. McKaughan, an air-quality expert with the federal Environmental Protection Agency's Region 9, said the Four Corners region has air so clean that it can absorb additional pollutants without harm. She said the EPA had no significant concerns about the proposed coal-fired Desert Rock plant.

V. Any uncertainty associated with the option There is a high level of uncertainty in getting something like this passed politically and how long it would take is an unknown.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues Oil and Gas Work Group, Other Sources Work Group.

OVERARCHING: MERCURY

Mitigation Option: Clean Air Mercury Rule Implementations in Four Corners Area

I. Description of the mitigation option
States and tribes are presently drafting regulations (some such as NM and CO now have completed rules, see appendix on NM & CO) to meet the Clean Air Mercury Rule (CAMR) while simultaneously meeting their mission to protect public health and the environment. For states, this means allocating mercury allowances to electric generating facilities to operate. CAMR may eventually have profound effects on the amount of mercury reduced from the affected facilities.

States participating in the Task Force might work in concert to determine if even greater reductions are possible than initially scheduled in CAMR. Some examples of working in concert might include:

- "Incentivizing" early mercury reductions at CAMR-affected facilities;
- Retiring any excess allowances that may exist (Colorado has in effect a "Colorado Citizens' Trust" to effectively permanently set aside excess allowances);
- Addressing the concerns for local mercury impacts ("hot spots") from new and proposed facilities in the Four Corners area by requesting that State air quality permitting agencies consider this hot spot criterion in their decision to approve/disapprove facilities' air quality permit requests (as individual state budgets and their "set aside allowances" may be inappropriate indicators of the impacts the local area might receive from power plants in Four Corners);
- Promoting additional mercury studies (e.g., air deposition) that would benefit Four Corners area (could/should be tied to option #5);
- Requiring early installation of mercury CEMs at facilities (to better gauge effectiveness of various co-control efforts);
    - For example, Mercury CEMs will be installed on 2 of the 4 units at San Juan by 12/31/07 and the other 2 units by 12/31/08.
- Developing more stringent control requirements for facilities in Four Corners Area;
- Other examples as identified.

II. Description of how to implement
A. Mandatory or voluntary:
Could be either mandatory or voluntary depending on the specifics of the option.

Differing Opinion: Since many of Four Corners Area lakes, streams, and rivers are currently under a mercury advisory, mandatory control of mercury is necessary. The health of humans and other living beings is at risk

B. Indicate the most appropriate agency(ies) to implement:
States' environmental (permitting) agencies

III. Feasibility of the option
A. Technical: Some of the technical options may be difficult to implement, especially depending on the timing. That is, CAMR plans are due to EPA by November 2006 and hence options developed here may come too late. However, options developed here could be possibly used in the states' future allocation schemes and/ or approaches surrounding CAMR.
B. Environmental: N/A
C. Economic: Difficult to ascertain as this depends on the specifics of the option developed.

IV. Background data and assumptions used

CAMR information and data are plentiful; however, the long-term application and effectiveness of various strategies to reduce mercury from power plants is difficult to predict.

Basic Information on New Mexico CAMR:

- Rule applicability covers coal-fired EGUs (presently 4 units at San Juan Generating Station and 1 unit at Escalante Generating Station).
- Mandatory mercury monitoring by sources begins 1/1/09.
- Mercury limitations become effective 1/1/10.
- See Tables 1 and 2, below, for mercury emissions data and proposed limitations.
- Monitoring includes installing monitoring systems (CEMS or sorbent traps), certification, performance test, and recording, quality-assuring, and reporting data.
- Initial monitoring performance test is 12 months (calendar year 2009).
- State rules takes state "budget" and turns it into state "cap" with portions of the cap assigned to facilities as facility-wide emission limitations as well as EPA-recommended new source set-aside.
- State rules prohibit participation in trading and banking program.
- State rules establish emissions fees to support one full-time equivalent for implementation of the mercury rules.

Table 1: New Mexico Mercury Emissions Data	
New Mexico Mercury Emissions (1999 EPA data; Tons)	1.09
New Mexico Mercury Emissions (2004 TRI data; SJGS + Escalante; Tons)	0.389
New Mexico Mercury Budget (2010-2017; Tons per year)	0.299
New Mexico Mercury Budget (2018 and after; Tons per year)	0.118

Table 2: New Mexico Mercury Limitations (Per year)						
	2010-2017			**2018 and after**		
	Tons	Ounces	%	Tons	Ounces	%
Total "State Cap"	0.299	9,568	100 %	0.118	3,776	100 %
San Juan Generating Station	0.244	7,808	81.6 %	0.104	3,323	88 %
Escalante Generating Station	0.04	1,280	13.4 %	0.01	340	9 %
New Source Set-Aside	0.015	480	5 %	0.035	113	3 %

Basic Information on Colorado CAMR:

Overview: Colorado's Air Quality Control Commission adopted a rule specific to CO's Utility Hg Reduction Program on 2/6/07. This rule specifies 100% of the state's allowances be transferred into the State's General Account. The State allocates allowances to units based on annual actual emissions, up to Model Rule allocations with an option to access additional allowances based on need through a safety-valve. In addition, the rule requires phased reductions over time on a rolling 12-month average basis, exempting low mass emitters and new units with existing permits in place:

• 2012: Pawnee and Rawhide 0.0174 lb/GWh or 80% inlet Hg capture;
• 2014: 0.0174 lb/GWh or 80% inlet Hg capture; and
• 2018: 0.0087 lb/GWh or 90% inlet Hg capture.

This rule allows for averaging of units at the same plant. The rule also provides soft-landing, requiring Best Available Mercury Control Technology installation if units demonstrate to the State that they cannot meet the performance standard. Finally, the rule includes a provision associated with retirement of allowance accrual, beginning in 2016, 2019 and every five years thereafter, if no separate rulemaking is commenced prior.

Trading: Yes, but allocations are made based on actual emissions.

Allowance Allocations: Up to 95% in phase I and 97% in phase II, with the remainder used for new units. However, actual allocations are made based on actual emissions, which are reduced over time due to state-only Hg emission standards. Therefore allocation amounts are also expected to decrease over time.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium – again, the long term application and effectiveness of various strategies to reduce mercury from power plants is difficult to predict.

VI. Level of agreement within the work group for this mitigation option

TBD.

VII. Cross-over issues to the other Task Force work groups

TBD.

Mitigation Option: Federal Clean Air Mercury Rule (CAMR) Implementation on the Navajo Nation

I. Description of the mitigation option

The Environmental Protection Agency (EPA) promulgated the Clean Air Mercury Rule (CAMR) on May 18, 2005. CAMR established a mechanism by which mercury (Hg) emissions from new and existing coal-fired power plants (EGUs) are capped at nation-wide levels of 38 tons/year effective in 2010 and 15 tons/year effective in 2018. EPA then established Hg emission levels for each state and for Indian country in cases where there are existing EGUs; this includes the Navajo Nation. State and Tribal plans to implement and enforce Hg emission levels were to be submitted to EPA by November 17, 2006. State plans can be more stringent than the EPA Model Rule and may or may not allow trading or banking of emissions allowances.

In cases where a State or Indian Tribe does not have an approvable plan in place by the prescribed deadline of March 17, 2007, EPA may implement a Federal plan by May 17, 2007. In order to facilitate this action, EPA published proposed rules on December 22, 2006. These rules are expected to be finalized by May 17, 2007, and will be used to implement CAMR on the Navajo Nation. A major shortcoming of these EPA rules is the lack of provision for meaningful public participation in the process to develop and allocate specific Hg emission limits for existing and proposed EGUs on Navajo Nation lands. This is significant since the Navajo Nation mercury emissions budget is larger than that of either Arizona, New Mexico, or Utah, and almost as large as the budget for Colorado.

The Navajo EPA, Region 9 EPA, and the operating agencies for the Four Corners Power Plant and the Navajo Generating Station – Arizona Public Service Company (APS) and the Salt River Project Agricultural Improvement and Power District (SRP), respectively – have already had discussions regarding a potential allocation methodology for the Navajo Nation. A meeting was held on July 10, 2006, at which Region 9 EPA presented a “strawman” proposal which differed significantly from the EPA model Rule with respect to the amount and disposition of the new source set-aside portion. This proposal has not been well-received by APS and SRP. The degree to which the air quality agencies in the surrounding, contiguous, and sometimes overlapping States of Arizona, Colorado, New Mexico and Utah have been aware of these early meetings is not known. From all appearances it seems that much greater effort should go towards facilitating adequate public participation in this process. The prime responsibility for achieving this rests with Region 9 EPA.

At a minimum the process for allocation of mercury emissions limits to EGUs in Navajo lands should be at least as open to public participation as the most transparent State CAMR process has been. For the Navajo Nation this might include informational meetings and public hearings in Window Rock and Page, Arizona, and Farmington, New Mexico. Final decisions on nature and location of meetings should be negotiated among the various jurisdictional agencies.

II. Description of how to implement

A. Mandatory or voluntary

This should be mandatory. In the past, public participation has been a cornerstone of EPA policy and in fact is mandated in many of their regulations.

B. Indicate the most appropriate agencies to implement

Region 9 EPA, with assistance and cooperation of Navajo EPA and air quality agencies in affected States.

III. Feasibility of the option

A. Technical: Entirely feasible

B. Environmental: Feasible

Economic: Feasible; minor administrative costs to conduct public meetings and hearings
Political: Medium feasibility. Some advocacy to Region 9 EPA may be needed to implement this option.

IV. Background data and assumptions used
A small amount of information has been received from Region 9 EPA.
Clean Air Mercury Rule making process is in process so newer information may now be available

V. Any uncertainty associated with the option
Medium – responsibility to implement rests primarily with Region 9 EPA.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other Task Force work groups TBD

OVERARCHING: AIR DEPOSITION STUDIES

Mitigation Option: Participate in and Support Mercury Studies

I. Description of the mitigation option

Background

Rationale and Benefits: Methyl mercury is a known neurotoxin affecting humans and wildlife. Coal-fired power plants are the number one source of mercury emissions in the United States[1]. The Four Corners already is home to several power plants that are large emitters of mercury and additional coal-powered plants are proposed for the region. Individuals and community groups in the San Juan Mountains have expressed great concern about mercury emissions in our region and the existing mercury fish consumption advisories in several reservoirs. Studies of mercury in air deposition, the environment and in sensitive human populations (such as pregnant women) are necessary to set a baseline for current levels and to detect future impacts of increased mercury emissions on these sensitive human populations and natural resources, including the Weminuche Wilderness, a Federal Class I Area.

Existing mercury data for the Four Corners region: Total mercury in wet deposition has been monitored at Mesa Verde National Park since 2002 as part of the Mercury Deposition Network (MDN)[2]. Results show mercury concentrations among the highest in the nation. Mercury concentrations have been measured in snowpack at a few sites in the San Juan Mountains by the USGS[3] and moderate concentrations similar to the Colorado Front Range have been recorded. Mercury concentrations in sport fish from several reservoirs have exceeded the 0.5 microg/g action level resulting in mercury fish consumption advisories for McPhee, Narraguinnep, Navajo, Sanchez and Vallecito Reservoirs [4]. Sediment core analysis for Narraguinnep Reservoir show that mercury fluxes increased by approximately a factor of two after about 1970[5]. Finally, atmospheric deposition just to the surface of McPhee and Narraguinnep Reservoirs (i.e., not including air deposition to the rest of the watershed) is estimated to contribute 8.2% and 47.1% of total mercury load to these waterbodies, respectively[6].

Data Gaps: Very little data exists for the Four Corners Region with which to assess current risks and trends over time for mercury in air deposition, ecosystems, and sensitive human populations. Mercury amounts and concentrations in wet deposition at Mesa Verde National Park are not likely to portray the situation in the mountains where mercury may be deposited at higher concentrations and total amounts because of greater rates of precipitation and the process of cold condensation, which causes volatile compounds to migrate towards colder areas at high elevation and latitude[7]. No information about total mercury deposition from the atmosphere (i.e., including dry deposition) exists for low or high elevations in the Four Corners Region. Furthermore, analysis of sources of air deposition of mercury is lacking. Except for a handful of reservoirs, no information exists for incorporation of mercury into aquatic ecosystems and subsequent effects on food-webs. No systematic effort exists to document mercury impacts in a wide range of waterbodies over space and time. Lastly, impacts of mercury exposure to human populations are unknown.

Three new studies have begun or will begin in 2007, however. In 2007, the Mountain Studies Institute (MSI) will measure total mercury in bulk atmospheric deposition (collector near NADP station at Molas Pass), in lake zooplankton (invertebrates eaten by fish), and in lake sediment cores in the San Juan Mountains, a project funded by the U.S. EPA and USFS[8]. Dr. Richard Grossman is measuring mercury levels in hair collected from pregnant women in the Durango vicinity. Lastly, the Pine River Watershed Group (via the San Juan RC&D) recently was granted start-up funds to initiate event-based sampling of mercury in atmospheric deposition at Vallecito Reservoir and accompanying back-trajectory analyses to locate the source of these storm events.

Option 1: Install and operate a long-term monitoring station for mercury in wet deposition for a location at high elevation where precipitation amounts are greater than the site at Mesa Verde NP. Co-location of the collector with the NADP site at Molas Pass would provide data pertinent to Weminuche Wilderness and the headwaters of Vallecito Reservoir. This monitor would be part of the Mercury Deposition Network (MDN). Upgrading the NADP monitoring equipment at Molas Pass to include the MDN specifications would cost $5,000 to $6,000, while annual monitoring costs are $12,112 plus personnel as of September 2006.

Option 2: Install and operate a long-term monitoring station for mercury in total deposition (wet and dry) for at least one MDN station in the Four Corners Region. Speciated data will be collected and analyzed as is feasible. The MDN is currently developing this program and costs are anticipated at about $50,000 per year.

Option 3: Support multi-year comprehensive mercury source apportionment study to investigate the impact of local and regional coal combustion sources on atmospheric mercury deposition. This type of study would require additional deposition monitoring (i.e., recommendations 1 & 2 above). Speciated data will be collected and analyzed as is feasible. A mercury monitoring and source apportionment study was recently completed for eastern Ohio. (http://pubs.acs.org/cgibin/asap.cgi/esthag/asap/html/es060377q.html[9]). This study would build on the pilot study planned for Vallecito Reservoir. Costs TBD.

Option 4: Support a study of mercury incorporation and cycling in aquatic ecosystem food-webs, including total and methyl mercury in the food-webs of lakes and wetlands. This option includes studies that determine which ecosystems currently have high levels of total and methyl mercury in food-web components, how mercury levels in ecosystems change over time, where the mercury is coming from, and what conditions are causing the mercury to become methylated (the toxic form of mercury that bio-accumulates in food-webs). This information would allow tracking of mercury risks over time and space and serves as the basis for predicting future impacts. Existing reservoir studies and the upcoming MSI investigation serve as a starting point to build a collaborative and systematic approach. Costs TBD.

Option 5: Support continued studies of mercury concentrations in sensitive human populations in the region to understand what exposure factors increase likelihood of unhealthy mercury levels in the body. Dr. Richard Grossman's study serves as a starting point to continue this effort. Costs TBD.

Option 6: Form a multi-partner Mercury Advisory Committee that would work collaboratively to prioritize research and monitoring needs, develop funding mechanisms to sustain long-term mercury studies, and work to communicate study findings to decision-makers. The Committee would include technical experts and stakeholder representatives from States, local governments, land management agencies, watershed groups, the energy industry, etc.

II. Description of how to implement

See above. Studies would utilize the existing Mercury Deposition Network and expertise developed from past and ongoing studies. Investigators could include scientists from academia, non-profit, private and government organizations and agencies.

III. Feasibility of the Option

Technical -Very feasible; all technology exists or is in development for the above options.

Environmental – Very feasible. Harmful effects on the environment are negligible and permits for sample collection should be easy to obtain.

Financial – Uncertain. It is likely that a consortium of funding entities collaborate for these options. Potential partners include States, industry, US-EPA, USDA-Forest Service, US-Department of Energy, and local governments, watershed groups and public health organizations.

IV. Background data and assumptions used See introduction section

V. Any uncertainty associated with the option Funding uncertainty.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups Energy and Monitoring Groups

Citations:

[1] See http://www.epa.gov/mercury/about.htm.

[2] National Atmospheric Deposition Program (NADP). Mercury Deposition Network http://nadp.sws.uiuc.edu/mdn/. National Trends Network. http://nadp.sws.uiuc.edu/.

[3] Campbell, D, G Ingersoll, A Mast and 7 Others. Atmospheric deposition and fate of mercury in high-altitude watersheds in western North America. Presentation at the Western Mercury Workshop. Denver, CO. April 21, 2003.

[4] Colorado Department of Public Health and Environment website: http://www.cdphe.state.co.us/wq/FishCon/FishCon.htm and http://www.cdphe.state.co.us/wq/monitoring/monitoring.html.

[5] Gray, JE, DL Fey, CW Holmes, BK Lasorsa. 2005. Historical deposition and fluxes of mercury in Narraquinnep Reservoir, southwestern Colorado, USA. Applied Geochemistry 20: 207-220.

[6] Colorado Department of Public Health (CDPHE). 2003. Total Maximum Daily Load for Mercury in McPhee and Narraguinnep Reservoirs, Colorado: Phase I. Water Quality Control Division. Denver, CO. http://www.epa.gov/waters/tmdldocs/Mcphee-NarraguinnepTMDLfinaldec.pdf.

[7] Schindler, D. 1999. From acid rain to toxic snow. Ambio 28: 350-355

[8] See http://www.mountainstudies.org/Research/airQuality.htm.

[9] See http://pubs.acs.org/cgi-bin/asap.cgi/esthag/asap/html/es060377q.html

OVERARCHING: GREENHOUSE GAS MITIGATION

Mitigation Option: CO_2 Capture and Storage Plan Development by Four Corners Area Power Plants

I. Description of the mitigation option

Carbon sequestration refers to the provision of long-term storage of carbon in the terrestrial biosphere, underground, or the oceans so that the buildup of carbon dioxide (the principal greenhouse gas) concentration in the atmosphere will reduce or slow. In some cases, this is accomplished by maintaining or enhancing natural processes; in other cases, novel techniques are developed to dispose of carbon.

Emissions of CO_2 from human activity have increased from an insignificant level two centuries ago to over twenty five billion tons worldwide today (1). The additional CO_2, a major contributor to Greenhouse gases, contribute to the phenomenon of global warming and could cause unwelcome shifts in regional climates (1).

The contribution of CO_2 from the 2 major power plants in the 4Corners area is approximately 29,000,000 Tons of CO_2 per year. The proposed Desert Rock Energy Project would add an approximate additional 11,000,000 Tons of CO_2 per year.

Facilities in the Four Corners area should begin developing carbon sequestration plans to mitigate this important global issue. Four Corners area power plants should research & develop way to reduce their CO_2 emissions.

Benefits: CO_2 emissions reductions would reduce the Greenhouse Gases output of the 4Corners area. Carbon sequestration would slow the buildup of CO_2 emissions in the atmosphere. It would be a regional action to reducing the trends of global warming. Benefits would be environmental and economic. CO_2 capture and injection may have a beneficial use for enhanced oil recovery in the 4C area

Tradeoffs: no tradeoffs

Burdens:

The benefits of protecting the climate will be realized globally and far in the future; the cost of each GHG emissions reduction project is local and immediate.

Cost to power plants, administrative costs.

Sequestration, isolating the CO_2 emissions is cheap; however, capturing/storing is expensive.

II. Description of how to implement

A. Mandatory or voluntary

Combination of mandatory and voluntary

Voluntary: 4C area power plants should begin developing Carbon Sequestration Plans

Mandatory limits or allocations may be set by State and Federal regulators in the near future.

B. Indicate the most appropriate agency(ies) to implement

State and Federal Regulators can allocate Carbon budgets which will lead to more controls

Appropriate State/Federal agencies to help assess Carbon potential storage areas as part of planning process

III. Feasibility of the option

A. Technical: Technologies exist; many are in R&D phase.
B. Environmental: Capturing and storing CO_2 emissions is difficult.
C. Economic: Capturing CO_2 emissions is expensive.
D. Legal: Liability of CO_2 storage process

IV. Background data and assumptions used

1. Carbon Sequestration Technology Roadmap and Program Plan 2006, US DOE
2. CO2 emissions from Four Corners area power plants (4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10)
3. San Juan Generating Station has a total 1798 MW generation capacity, and emits approximately 13,097,000 Tons CO_2/yr. Approx 7,300 Tons CO_2 per MW generation capacity. San Juan Generating Station CO_2 rationing by MW is used as an estimation for CO_2 emissions from Desert Rock Energy Facility. Based on this assumption, the CO_2 emissions from Desert Rock Energy Facility will be approximately 11,000,000 Tons/yr.
4. US DOE Carbon Sequestration Regional Partnerships:
http://www.fossil.energy.gov/programs/sequestration/index.html
New Mexico Partnerships
http://www.fossil.energy.gov/programs/projectdatabase/stateprofiles/2004/New_Mexico.html

V. Any uncertainty associated with the option

Medium.

VI. Level of agreement within the work group for this mitigation option.

To Be Determined.

VII. Cross-over issues to the other Task Force work groups

CO_2 emissions reduction Cross-over issue with other energy industries such as Oil & Gas. Oil & Gas industries could also be held responsible for developing Carbon sequestration plans.

CO_2 capture and injection may have a beneficial use for enhanced oil recovery in the Four Corners area.

Mitigation Option: Climate Change Advisory Group (CCAG) Energy Supply Technical Work Group Policy Option Implementation in Four Corners Area

I. Description of the mitigation option

The New Mexico Climate Change Advisory Group (CCAG) is a diverse group of stakeholders from across New Mexico. At the end of 2006, the group will put forth policy options for reducing greenhouse gas emissions in NM to 2000 levels by the year 2012, 10% below 2000 levels by 2020 and 75% below 2000 levels by 2050. 69 recommendations covering transportation, land use, energy supply, agriculture and forestry were made which if implemented would exceed emissions reduction target for 2020.

A GHG emissions inventory for New Mexico prepared by The Center for Climate Strategies (2) showed electricity generation to comprise 40% of the states GHG emissions. The electricity generation sector is a source contributor of GHG and there are many areas for potential reductions. In the future, if the proposed Desert Rock Energy Project comes online, the additional 11 million tons of CO2 from Desert Rock would increase the electricity generation portion of New Mexico GHG emissions to approximately 50%.

The energy supply technical work group drafted options for renewable portfolio standards and advanced coal technologies (1). These policy options should be applied to Four Corners area facilities. The contribution of CO_2 from the 2 major power plants in the 4Corners area is approximately 29,000,000 Tons of CO_2 per year. The proposed Desert Rock Energy Project would add an additional estimated 11,000,000 Tons of CO_2 per year (3).

Local State/Federal Regulating agencies should work with the existing and proposed power plants to collaborate to help realize the targets of the Climate Change Advisory Group. CO_2 sequestration technologies and other Greenhouse gas mitigation strategies should be assessed and implemented to meet the targets.

Benefits:
Environmental: reduction of greenhouse gas emissions to 2000 levels by the year 2012, 10% below 2000 levels by 2020 and 75% below 2000 levels by 2050. Mitigation of adverse climate change effects

Net economic savings for the state's economy

Tradeoffs: none
Burdens: Cost to existing and proposed power pants and administrators

II. Description of how to implement

A. Mandatory or voluntary
Combination of mandatory and voluntary

B. Indicate the most appropriate agency(ies) to implement
State and Federal Regulators:
Oil Conservation Division (NMOCD)
New Mexico Air Quality Bureau
New Mexico Energy, Minerals, and Natural Resources Division

Other Four Corner State Environmental Protection Agencies

III. Feasibility of the option

A. Technical: TBD
B. Environmental: TBD
C. Economic: TBD

IV. Background data and assumptions used
(1) New Mexico Climate Change Advisory Group (CCAG): http://www.nmclimatechange.us/
(2) Draft New Mexico Greenhouse Gas Inventory and Reference Case Projections, The Center for Climate Strategies, July 2005
(3) CO_2 emissions from Four Corners area power plants (4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV9)
(4) San Juan Generating Station has a total 1798 MW generation capacity, and emits approximately 13,097,000 Tons CO_2/yr. Approx 7,300 Tons CO_2 per MW generation capacity. San Juan Generating Station CO_2 rationing by MW is used as an estimation for CO_2 emissions from Desert Rock Energy Facility. Based on this assumption, the CO_2 emissions from Desert Rock Energy Facility will be approximately 11,000,000 Tons/yr.
(5) Carbon Sequestration Technology Roadmap and Program Plan 2006, US DOE

V. Any uncertainty associated with the option Medium.

VI. Level of agreement within the work group for this mitigation option
To Be Determined.

VII. Cross-over issues to the other Task Force work groups
Greenhouse Gas (GHG) emissions reduction Cross-over issue with other energy industries such as Oil & Gas.

OVERARCHING: CAP AND TRADE

Mitigation Option: Declining Cap and Trade Program for NO_x Emissions for Existing and Proposed Power Plants

I. Description of the mitigation option

Cap and trade is a policy approach to controlling large amounts of emissions from a group of sources at costs that are lower than if sources were regulated individually. The approach first sets an overall cap, or maximum amount of emissions per compliance period, that will achieve the desired environmental effects. Authorizations to emit in the form of emission allowances are then allocated to affected sources, and the total number of allowances cannot exceed the cap.

Individual control requirements are not specified for sources. The only requirements are that sources completely and accurately measure and report all emissions and then turn in the same number of allowances as emissions at the end of the compliance period.
For example, in the Acid Rain Program, sulfur dioxide (SO_2) emissions were 17.5 million tons in 1980 from electric utilities in the U.S. Beginning in 1995, annual caps were set that decline to a level of 8.95 million allowances by the year 2010 (one allowance permits a source to emit one ton of SO_2). At the end of each year, EPA reduces the allowances held by each source by the amount of that source's emissions (1, EPA Clean Air Markets).

A declining cap and trade program means that the cap would be slightly lowered over time to reduce the total NOx emissions in the Four Corners area. A declining cap and trade program would be effective for the Four Corner areas' electric generating units.
The power plants in the area have continuous emissions monitors. We can measure accurately each plant's NOx emissions. In 2005 the NO_x emissions from San Juan Generating Station were 27,000 tons. The Four Corners Power Plant emitted 42,000 tons (2). Desert Rock Energy facility would add an approximate 3,500 tons/yr (2). NO_x emissions from electricity generating units (EGUs) will continue to be reported and recorded under the EPA Acid Rain Program (3). So the data is available. For each of these facilities the costs for additional controls and NO_x emissions reductions is different.

Electric Generating Units (EGUs) will be defined as it is EPA's Clean Air Interstate Rule:
(a) Except as provided in paragraph (b) of this definition, a stationary, fossil-fuel-fired boiler or stationary, fossil fuel fired combustion turbine serving at any time, since the start-up of a unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.
(b) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (a) of this definition starting on the day on which the unit first no longer qualifies as a cogeneration unit.

The program will cover all EGUs.

The Four Corners area declining cap and trade program would cap NO_x levels from EGUs at current levels. The cap could be lowered 5% every 10 years or a collaboratively agreed on level.

The Declining cap and trade program would include all EGUs in the Four Corners area, and could also possible be extended to oil & gas sources. New sources could obtain offsets.

There should be some discussion regarding how the cap would be set; as well as how to protect against hot spots.

<u>Benefits:</u> The cap will prevent NO_x emissions from the Four Corners area sources from increasing. Regardless of new power plants, sources will have to find a way to keep overall NO_x emissions below the declining cap.

The program will reduce NO_x emissions in the Four Corners area.
Power Plants would continue to look at new ways to reduce emissions.

Differing Opinion: Cap and trade is a band aid approach to reduction of emissions. It may look good on paper, but does nothing to enhance the air quality. Cap and trade should not be an option for power plant or oil and gas emissions in the Four Corners Area. Extensive improvement of the air quality and consideration for the health and welfare of the people and the environment should be the top priority.

<u>Tradeoffs:</u> None

Differing Opinion: The trade off of cap and trade is that the numbers look good, but in reality, the emissions are still in existence.

<u>Burdens:</u>
Regulatory agency needs to be able to collect, verify all emissions information and be able to enforce rule

<u>II. Description of how to implement</u>
A. <u>Mandatory or voluntary</u>
Mandatory

B. <u>Indicate the most appropriate agency(ies) to implement</u>
State Air Quality Agencies and Federal EPA

<u>III. Feasibility of the option</u>
A. Technical: NO_x emissions are measured using CEMS by large Power Plants. Complete and verified emissions measurements are reported by the Four Corners area power plants and is available on the EPA Clean Air Markets: Data and Maps National Database: http://cfpub.epa.gov/gdm/

B. Environmental: NO_x control technologies are available.
C. Economic: The design and operation of the program are relatively simple which helps keep compliance and administrative costs low. Cost savings are significant because regulators do not impose specific reductions on each source. Instead, individual sources choose whether and how to reduce emissions or purchase allowances. Regulators do not need to review or need to approve sources' decisions, allowing them to tailor and adjust their compliance strategies to their particular economics (1). Power Plants may need retrofits or to buy or sell credits.

* Cumulative Effects Work Group: How would a 5% declining cap and trade program for NO_x in the Four Corners area affect visibility and ozone levels?

<u>IV. Background data and assumptions used</u>

1. EPA Clean Air Markets – Air Allowances
http://www.epa.gov/AIRMARKET/trading/basics/index.html

A cap and trade program also is being used to control SO_2 and nitrogen oxides (NO_x) in the Los Angeles, California area. The Regional Clean Air Incentives Market (RECLAIM) program began in 1994. [1]

2. NO_2 emissions from Four Corners area power plants
(4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV9)
*NO_x emissions from existing power plants obtained from EPA Acid Rain database
*NO_x emissions from proposed Desert Rock Energy Facility from AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)

3. EPA Clean Air Markets: Data and Maps National Database: http://cfpub.epa.gov/gdm/

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option To Be Determined.

VII. Cross-over issues to the other Task Force work groups
Declining Cap and Trade program would cross-over with Oil & Gas work group.

Mitigation Option: Four Corners States to join the Clean Air Interstate Rule (CAIR) Program

I. Description of the mitigation option

EPA finalized the Clean Air Interstate Rule (CAIR) on March 10, 2005. It is expected that this rule will result in the deepest cuts in sulfur dioxide (SO_2) and nitrogen oxides (NOx) in more that a decade (1).

The Clean Air Interstate Rule establishes a cap-and-trade system for SO_2 and NO_x based on EPA's proven Acid Rain Program. The Acid Rain Program has produced remarkable and demonstrable results, reducing SO_2 emissions faster and cheaper than anticipated, and resulting in wide-ranging environmental improvements. EPA already allocated emission "allowances" for SO2 to sources subject to the Acid Rain Program. These allowances will be used in the CAIR model SO2 trading program. For the model NOx trading programs, EPA will provide emission "allowances" for NOx to each state, according to the state budget. The states will allocate those allowances to sources (or other entities), which can trade them. As a result, sources are able to choose from many compliance alternatives, including: installing pollution control equipment; switching fuels; or buying excess allowances from other sources that have reduced their emissions. Because each source must hold sufficient allowances to cover its emissions each year, the limited number of allowances available ensures required reductions are achieved. The mandatory emission caps, stringent emissions monitoring and reporting requirements with significant automatic penalties for noncompliance, ensure that human health and environmental goals are achieved and sustained. The flexibility of allowance trading creates financial incentives for electricity generators to look for new and low-cost ways to reduce emissions and improve the effectiveness of pollution control equipment (1).

While most of the states are in the Eastern half of the US, Texas is participating in the CAIR program. Four Corners states could also participate and realize the emissions reduction benefits of CAIR.

SO_2 and NO_x contribute to the formation of fine particles and NO_x contributes to the formation of ground-level ozone. Fine particles and ozone are associated with thousands of premature deaths and illnesses each year. Additionally, these pollutants reduce visibility and damage sensitive ecosystems (1).

By the year 2015, the Clean Air Interstate Rule will result in (Eastern US benefits) (1):
-- $85 to $100 billion in annual health benefits, annually preventing 17,000 premature deaths, millions of lost work and school days, and tens of thousands of non-fatal heart attacks and hospital admissions.
-- nearly $2 billion in annual visibility benefits in southeastern national parks, such as Great Smoky and Shenandoah.
-- significant regional reductions in sulfur and nitrogen deposition, reducing the number of acidic lakes and streams in the eastern U.S.

Based on an assessment of the emissions contributing to interstate transport of air pollution and available control measures, EPA has determined that achieving required reductions in the identified states by controlling emissions from power plants is highly cost effective (1).

States must achieve the required emission reductions using one of two compliance options: 1) meet the state's emission budget by requiring power plants to participate in an EPA-administered interstate cap and trade system that caps emissions in two stages, or 2) meet an individual state emissions budget through measures of the state's choosing (1).

CAIR provides a Federal framework requiring states to reduce emissions of SO_2 and NO_x. EPA anticipates that states will achieve this primarily by reducing emissions from the power generation sector.

These reductions will be substantial and cost-effective, so in many areas, the reductions are large enough to meet the air quality standards.

The Clean Air Act requires that states meet the new national, health-based air quality standards for ozone and PM2.5 standards by requiring reductions from many types of sources. Some areas may need to take additional local actions. CAIR reductions will lessen the need for additional local controls (1).

This final rule provides cleaner air while allowing for continued economic growth. By enabling states to address air pollutants from power plants in a cost effective fashion, this rule will protect public health and the environment without interfering with the steady flow of affordable energy for American consumers and businesses.

CAIR Timeline:
Promulgate CAIR Rule 2005, State implementation Plans Due 2006, Phase I Cap in Place for NOX, Phase I Cap in Place for SO2, Phase II Cap in Place for NOx and SO_2 (1). Caps will be fully met in 2015 to 2020, depending on banking.

The Four Corners area has existing and proposed power plants with significant NO_x and SO_2 emissions. The problem occurs over a relatively large area, there are a significant number of sources responsible for the problem, the cost of controls varies from source to source, and emissions can be consistently and accurately measured. Cap and Trade programs typically work better over broader areas. The Four Corners area as well as each state would realize a more successful Cap and Trade program from being a part of a large interstate program such as CAIR.

By joining the EPA CAIR program, the 4 Corner states of New Mexico, Colorado, Arizona, and Utah will also benefit from the interstate SO_2 and NOx emissions reductions.

Need some discussion on how to set cap, and protect against hot spots.

<u>Benefits:</u>
"If states choose to meet their emissions reductions requirements by controlling power plant emissions through an interstate cap and trade program, EPA's modeling shows that (for eastern states):

- In 2010, CAIR will reduce SO_2 emissions by 4.3 million tons -- 45% lower than 2003 levels, across states covered by the rule. By 2015, CAIR will reduce SO2 emissions by 5.4 million tons, or 57%, from 2003 levels in these states. At full implementation, CAIR will reduce power plant SO_2 emissions in affected states to just 2.5 million tons, 73% below 2003 emissions levels.
- CAIR also will achieve significant NOx reductions across states covered by the rule. In 2009, CAIR will reduce NOx emissions by 1.7 million tons or 53% from 2003 levels. In 2015, CAIR will reduce power plant NOx emissions by 2 million tons, achieving a regional emissions level of 1.3 million tons, a 61% reduction from 2003 levels. In 1990, national SO_2 emissions from power plants were 15.7 million tons compared to 3.5 million tons that will be achieved with CAIR. In 1990, national NO_x emissions from power plants were 6.7 million tons, compared to 2.2 million tons that will be achieved with CAIR (1)."

<u>Tradeoffs:</u> None
<u>Burdens:</u> Administrative costs on regulating agencies, including how to determine state or regional level cap; emissions control upgrade costs or purchasing allowances to power plants

<u>II. Description of how to implement</u>
A. <u>Mandatory or voluntary</u>

Mandatory emission caps, stringent emissions monitoring and reporting requirements with significant automatic penalties for noncompliance, ensure that human health and environmental goals are achieved and sustained (1).

B. Indicate the most appropriate agency(ies) to implement
State Air Quality Agencies and Federal EPA

III. Feasibility of the option
A. Technical: NOx emissions are measured using CEMS by large Power Plants. Complete and consistent emissions measurement and reporting by all sources guarantees that total emissions do not exceed the cap and that individual sources' emissions are no higher than their allowances

B. Environmental: NO_x, SO_2 control technologies are available.

C. Economic: The design and operation of the program are relatively simple which helps keep compliance and administrative costs low (2).

Cost savings are significant because EPA does not impose specific reductions on each source. Instead, individual sources choose whether and how to reduce emissions or purchase allowances. EPA does not review or need to approve sources' decisions, allowing them to tailor and adjust their compliance strategies to their particular economics (2).

The flexibility of allowance trading creates financial incentives for electricity generators to look for new and low-cost ways to reduce emissions and improve the effectiveness of pollution control equipment (1).

IV. Background data and assumptions used
1. EPA Clean Air Interstate Rule: http://www.epa.gov/cair/
2. EPA Clean Air Markets – Air Allowances
http://www.epa.gov/AIRMARKET/trading/basics/index.html
3. "EPA Enacts Long-Awaited Rule To Improve Air Quality, Health" Rick Weiss, Washington Post, Friday, March 11, 2005; Page A01 http://www.washingtonpost.com/wp-dyn/articles/A23554-2005Mar10.html
4. The White House – Council on Environmental Quality, Cleaner Air,
http://www.whitehouse.gov/ceq/clean-air.html

V. Any uncertainty associated with the option
Low – Program is based on a proven cap and trade approach
Need mechanism to be assured that a significant portion of actual reductions are achieved in the Four Corners area to assure the environmental benefit.

VI. Level of agreement within the work group for this mitigation option
To Be Determined

VII. Cross-over issues to the other Task Force work groups
Clean Air Interstate Rule would cross-over with Oil & Gas work group

OVERARCHING: ASTHMA STUDIES

Mitigation Option: Chronic Respiratory Disease Study for the Four Corners area to determine relationship between Air Pollutants from Power Plants and Respiratory Health Effects

I. Description of the mitigation option

This option would involve conducting a chronic respiratory disease study for the Four Corners area to determine the relationship between air pollutants from power plants and respiratory health effects. On going studies are necessary to continue to evaluate health risks associated with the large number of combustion emission sources in the area, primarily the two large coal-fired power plants in the area. Cumulatively, the two largest power plants in the area emit approx 66,000 tons/yr of nitrogen oxides (1). Nitrogen oxides are key precursor emissions to ozone.

Background

The NM Department of Health conducted a pilot project that linked daily maximum 8-hour ozone levels with the number of asthma-related emergency room visits at San Juan Regional Medical Center located in northwestern NM. The ozone and ER asthma data were collected for the period of 2000 - 2003. The number of emergency room visits in the summer increased 17% for every 10 ppb increase in ozone levels. This relationship occurred particularly following a two day lag and was statistically significant. These results are in general agreement with studies in other states and provide a foundation for tracking asthma-ozone relationships over time and space in NM (2).

The New Mexico Environment Department Air Quality Bureau operates and maintains three continuous ozone monitors in San Juan County. The eight-hour ozone design value in San Juan County has been maintained below the National Ambient Air Quality Standard for ozone of 0.08 ppm. The final eight-hour ozone design value for 2005 for San Juan County (San Juan Substation and Bloomfield monitors) was 0.072 ppm. The 2006 eight-hour ozone design value for San Juan County Substation monitor was 0.071 ppm. The 2006 eight-hour ozone design value for the San Juan County Bloomfield monitor was 0.069 ppm.

The Colorado Department of Public Health and Environment (CDPHE) has also researched asthma and links to environmental conditions. In a recent paper, “Holistic Approaches for Reducing Environmental Impacts on Asthma”, CDPHE, discusses staff researcher’s efforts to bring clarity to any identifiable linkage between environmental conditions and asthma. CDPHE investigated asthma rates throughout the state and compared these data against known and anecdotally reported information. Findings indicate that regions of Colorado do appear to have a higher incidence of asthma rates. In addition, some of the identified regions were not previously anticipated (e.g., rural communities), highlighting the need for further investigations (4).

The study describes asthma as a serious, chronic condition that affects over 15 million people in the United States. Asthma is a disease characterized by lung inflammation and hypersensitivity to certain environmental “triggers” such as pollen, dust, humidity, temperature and various environmental pollutants (dust, ozone, etc.), among others. Colorado has a particular problem with the occurrence of this condition, but the reasons for this are not well understood. Statewide there are an estimated 283,000 people with asthma, a figure that well exceeds national expectations. (4).

The CO-benefits risk assessment (COBRA) model is a recently developed screening tool that provides preliminary estimates of the impact of air pollution emission changes on ambient particulate matter (PM) air pollution concentrations, translates this into health effect impacts, and then monetizes these impacts

(5). A model such as this could be expanded to include other forms of air pollution such as ozone and be customized for the Four Corners Area.

Overarching modeling results should be cross-checked with local hospital inventory results and compared with other locations in the United States.

Benefits: Study would allow Four Corner area planning agencies to make better decisions and give the public a better idea of risk assessments

Tradeoffs: None

Burdens: Resources needed to conduct study

II. Description of how to implement

A. Mandatory or voluntary
Conduct coordinated outreach to obtain grant funding for the study.
(Study to be conducted by the end of 2009, with model development for assessing situation annually)

B. Indicate the most appropriate agency(ies) to implement
The states, the Environmental Protection Agency (EPA), and American Lung Association collaboration.

The need for these studies is obvious and the cost should be passed on to the utilities (and therefore the customers). However, even if these new studies find a significantly negative relationship between chronic respiratory disease and air pollutants, we already have proof that air pollutants increase the incidence of asthma. This mitigation option should include plans to utilize the study results for actively engaging policy-makers and changing regulations and enforcement, especially in geographic hot spots.

III. Feasibility of the option (indicate if assistance is needed from Cumulative Effects and/or Monitoring work groups)

Technical: The state and federal health organizations should be able to develop a 4C area model to assess the relationship between air pollutants from power plants and respiratory health effects

Environmental: Need for further modeling of Four Corners area customized to assessing respiratory health effect relationship to air pollutants from power plants. Existing COBRA model may be used as a starting point.

Economic: Grant funding would be required

*Monitoring work group: Assess whether or not we have the adequate data from monitoring stations to assess asthma situation. VOC and NOx emissions are contributors to ozone. Do we have good VOC data in the 4C area?

*Cumulative Effects work group: Assess the ozone trends in the 4C area. On average are ozone levels increasing or decreasing? Where are locations in the Four Corners area with the highest ozone concentrations? What are the relative contributions from power plants compared to oil and gas & other sources?

IV. Background data and assumptions used

(1) EPA Clean Air Markets – Data and Maps Query (2004 2005 2006 Facility & Unit Emissions Reports)
(2) New Mexico Department of Health Ozone Study
(3) New Mexico Environment Department – Ambient Ozone Level Data

(4) Holistic Approaches for Reducing Environmental Impacts on Asthma, Paper # 362, Prepared by Mark J. McMillan, Mark Egbert, and Arthur McFarlane, Colorado Department of Public Health and Environment.
(5) User's Manual for the CO-Benefits Risk Assessment (COBRA) Screening Model, US EPA, June 2006

V. Any uncertainty associated with the option Medium

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups Oil and Gas and Other Sources Work Groups

OVERARCHING: CROSSOVER

Mitigation Option: Install Electric Compression

I. Description of the mitigation option

Overview

- Electric Compression would involve the replacement or retrofit of existing internal combustion engines or proposed new engines with electric motors. The electric motors would be designed to deliver equal horsepower to that of internal combustion engines. However, the limitation of doing so is predicated by the electrical grid that would exist in a given area to provide the necessary capacity to support electrical compression.

According to projections, at least 12,500 new gas wells will be drilled in the San Juan Basin over the next 20 years. It is said that this gas field is loosing pressure and compression on thousands of wells is necessary. Pollution emissions from production engines are rapidly increasing. To date, there is no cumulative emissions measurement.

Using BLM figures, an average gas powered wellhead compressor at 353,685 hp-hr per year at 13.15g per hp-hr = 4,650,957 g/year of NO_x. This is just an example of NO_x emissions. This figure does not account for other compounds in exhaust emissions such as VOCs, carbon monoxide, etc. This is equivalent to a 17 car motorcade running non-stop, circling your house 24 hours per day.

Gas powered wellhead compressors and pumpjacks are being installed in close proximity to inhabited homes and institutions. The City of Aztec required electric compressors, although that ordinance was not enforced, on wellhead engines within the city limits prior to 2004 when the ordinance was revised. Electric engines were required in order to protect citizens from noxious emissions from gas fired engines near homes. Electric engines are thought to be quieter than gas fired engines; therefore reducing noise pollution also.

Gas fired engines are being installed on wells in close proximity to existing electric lines. Electric engines should be required on all sites near power lines especially near homes. In areas where there is no electricity, best available technology must be implemented such as 2g/hp/hr engines, catalytic converters, etc.

Air Quality/Environmental

- Elimination of criteria pollutants that occur with the combustion of hydrocarbon fuels (natural gas, diesel, gasoline). Displacement of emissions to power generating sources (utilities).

Economics

- The costs to replace natural gas fired compressors with electric motors would be costly.
- The costs of getting electrical power to the sites would be costly. It could require a grid pattern upgrade which could costs millions of dollars for a given area.
- A routine connection to a grid with adequate capacity for a small electric motor can be $18K to $25K/site on the Colorado side of the San Juan Basin.
- A scaled down substation for electrification of a central compression site can range between $250K and $400K.
- Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small.

Tradeoffs

- While the sites where the electrical motors would be placed would not be sources of emissions, indirect emissions from the facilities generating the electricity would still occur such as coal fired power plants.
- Additional co-generation facilities would likely have to be built in the region to supply the amount of electrical power needed for this option. This would result in additional emissions of criteria pollutants from the combustion of natural gas for turbines typically used for co-generation facilities.
- There would need to be possible upgrades in the electrical distribution system. However, the limitation of doing so is predicated by the electrical grid that would exist in a given area to provide the necessary capacity to support electrical compression

Burdens

- The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary, depending upon the results of monitoring data over time.
B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies.

III. Feasibility of the option

A. Technical: Feasible depending upon the electrical grid in a given geographic area
B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Indirect emission implications for grid suppliers should be considered (e.g., coal-fired plants).
C. Economic: Depends upon economics of ordering electrical motors, the ability of the grid system to supply the needed capacity and the cost to obtain right of way to drop a line to a potential site.

IV. Background data and assumptions used

The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff.

V. Any uncertainty associated with the option

Medium based upon uncertainties of obtaining electrical easements from landowners and/or land management agencies.

*A cumulative emissions inventory on all oil and gas field equipment is necessary
*If possible, a calculation of pollution related to electric power generation is needed for comparison to pollution emitted from gas powered engines.

VI. Level of agreement within the work group for this mitigation option

TBD.

VII. Cross-over issues to the other source groups

Oil and Gas Work Group
Cumulative Effects Work Group
Power Plant Work Group

OVERARCHING: CROSSOVER OPTIONS

Mitigation Option: Economic-Incentives Based Emission Trading System (EBETS) (Reference as is from Oil and Gas: see Oil and Gas Overarching Section)

Mitigation Option: Tax or Economic Development Incentives for Environmental Mitigation (Reference as is from Oil and Gas: see Oil and Gas Overarching Section)

FOUR CORNERS AREA POWER PLANTS FACILITY DATA TABLE

This data table was prepared by the Power Plants Work Group as a resource to help develop mitigation options. Facility data information was compiled from a variety of sources (see references). The last update of the table was August 2007. The Table, along with other resource information on Four Corners area power plants, is also available on the Task Force Website on the Power Plants Work Group Page, http://www.nmenv.state.nm.us/aqb/4C/powerplant_workgroup.html

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010 [10]
San Juan Generating Station [1]	PNM Resources (Owner/Operator)	Coal	ARP, EPA 9, Western Systems Coordinating Council	NMED - AQB	4 units, 1798 MW	PM- ESP	PM – 673 tons (2005)		PM – baghouse	13,097,406 tons (2005)	PM - 670 tons/yr
						SO_x - Wet Limestone	SO_2 – 16,570 tons (2005)	SO_2 – 16,179.3 tons (2004), 16,569.5 tons (2005) [4]	SO2 – enhanced scrubbing		SO2 - 8,900 tons/yr
						NO_x – Low-NOx burners / Over-fired air	NO_x – 26,809 tons (2005)	NO_x – 26,880.2 tons (2004), 26,809.0 tons (2005) [4]	NO_x – low-NO_x burners/ over-fired air / neural net		NOx - 18,500 tons/yr
						Hg – Wet scrubber	Hg – 766 lbs (2005)	CO_2 – 13,147,181.0 tons (2004), 13,097,410.1 tons (2005) [4]	Hg – activated carbon. Hg – CEMs		Hg - 275 lbs/yr
Four Corners Power Plant [2,3]	Arizona Public Service Company (Owner/Operator)	Coal	ARP, EPA 9	EPA Region 9, Navajo Nation EPA	5 units, 2040 MW	Units #1 - #3:	PM – 1,187 tons (2000-2005 annual average)		Considering available technologies for future regulatory changes [3]	15,913,105 tons (2000-2005 annual average)	N/A
						PM - Wet venturi scrubbers	SO_2 – 12,500 tons (2005)	SO_2 – 18,771 tons (2004), 12,554.2 (2005) [4]			

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010
Four Corners Power Plant [2,3] (cont.)						SOx - Dolomitic lime wet scrubbing	NO_x – 42,000 tons (2000-2005)	NO_x – 40,742 tons (2004), 41,743.4 tons (2005)			N/A
						NO_x – Low-NOx burners	Hg – Approx. 550-600 lbs/yr	CO_2 – 15,106,255 tons (2004), 16,015,408.7 tons (2005) [4]			
						Hg – Venturi scrubber					
						Units #4 & #5:					
						PM – Baghouses					
						SOx – Lime slurry wet scrubbing					
						NOx – Low-NOx burners					
						Hg – Wet scrubber, baghouses					
Proposed Desert Rock Energy Facility [5, 12]	Sithe Global Power, LLC (proposed owner/operator)	Coal		EPA Region 9, Navajo Nation EPA	2 units, 1500 MW [5]	PM – Baghouse [6, 12][1]	PM (TSP/PM) – 570 Tons/yr [6,12][3]		Hg – activated carbon if control < 90% and cost < $13,000/lb**	Approx. 12,700,000 tons/yr[8]	N/A
							PM_{10} – 1,120 Tons/yr [6, 12][4]				
						SOx –Wet Limestone FGD [6, 12][1]	SO_2 – 3,319 Tons/yr [6, 12]				
						NOx – low-NOx burners/ over-fired air / SCR [6,12]	NO_x – 3,325 Tons/yr [6, 12]				

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010
Proposed Desert Rock Energy Facility [5, 12] (cont.)						Hg – SCR +baghouse +FGD[2] [6, 12]	Mercury – 114 lbs/ yr [12]				N/A
							CO – 5,529 Tons/yr [12]				
						Hydrated Lime Injection & Wet Limestone FGD [12]	Lead – 11.1 Tons/yr [12] Flourides – 13.3 Tons/yr [12]				
						Hydrated Lime Injection & Wet Limestone FGD [12]	H_2SO_4 – 221 Tons/yr [12]				
Bluffview Power Plant [4]	City of Farmington (Owner/Operator) (Started 28-JUL-05)	Pipeline Natural Gas / Cogeneration	ARP, EPA 6		60 MW	Dry Low NOx Burners, Selective Catalytic Reduction		SO_2 – 0.7 tons/yr (2005) [4]		145997.3 tons (2005) [4]	N/A
								NO_x – 58.5 tons/yr (2005) [4]			
Milagro [4]	Williams Field Services (Owner/Operator)	Pipeline Natural Gas / Cogeneration	ARP, EPA 6		2 units, 61 MW [11]			SO_2 – 2.6 tons (2004), 2.5 tons (2005) [4]		498823.3 tons (2005) [4]	N/A
						NO_x – Dry Low-NOx burners		NO_x – 97.6 tons (2004), 110.2 tons (2005) [4]			

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010
Animas Power Plant [9]	City of Farmington (Owner/Operator)	Pipeline Natural Gas / Cogeneration	EPA 6, Western Systems Coordinating Council		51 MW [9]		SO2 – 0 (2005, turbine only) NOx – 54 Tons (2005, turbine) VOC – 54.3 Tons (2005, turbine) CO – 5.1 Tons (2005, turbine)				N/A
Bloomfield Generation [4]	Ameramex Energy Group, Inc. (Owner/Operator)		ARP, EPA 6								N/A
Navajo Dam Hydro Plant [9]	City of Farmington (Owner/Operator)	Water			30 MW [9]						N/A
Mustang Energy Project[7][5]	Proposed	Coal			300 MW		PM - 185 tons/yr SO_2 – 250 tons/yr NO_X - 125 tons/yr			Approx. 2,000,000 tons/yr[8]	N/A

[1] May 23, 2006 edit, info provided by Mike Farley (PNM), and in SJGS presentation for 4CAQTF, "SJGS Emissions Control Current and Future" http://www.nmenv.state.nm.us/aqb/4C/Docs/SanJuanGeneratingStation.pdf
[2] http://www.aps.com/general_info/AboutAPS_18.html [dl 5/29/06]
[3] APS Four Corners Power Plant tour handout (received 5/10/06), supplemental info provided by Richard Grimes (APS), in May 31 table edit

[4] EPA Clean Air Markets – Data and Maps Query (2004 2005 2006 Facility & Unit Emissions Reports)
[5] SITHE GLOBAL Desert Rock Energy Project FACT SHEET #1 DEC 2004 [dl 5/29/06]
[6] Application for Prevention of Significant Deterioration Permit for the Desert Rock Energy Facility, prepared by ENSR International May 2004
[7] Reference to Dave R. edits 6/2/06
[8] Desert Rock Energy Project Draft EIS Ch. 4.0 – Environmental Consequences May 2007
[9] Farmington Electric Utility Fact Sheet http://206.206.77.3/pdf/electric_utility/feus_fact_sheet.pdf (6/16/06) / NMED
[10] Info provided by Mike Farley (PNM)
[11] http://www.emnrd.state.nm.us/EMNRD/MAIN/documents/SER1_electricity.pdf
[12] AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01), Table 1, EPA Region 9 Air Programs: http://www.epa.gov/region09/air/permit/desertrock/#permit

[1] Subject to BACT - Best available control technology [6]
[2] Mercury (Hg) and HCL have been targeted under future regulation under maximum available control technology (MACT) [6]
[3] PM is defined as filterable particulate matter as measured by EPA Method 5.
[4] PM10 is defined as solid particulate matter smaller than 10 micrometers diameter as measured by EPA Method 201 or 201A plus condensable particulate matter as measured by EPA Method 202. EPA is treating PM10 as a surrogate for PM2.5.
[5] Outside of Scope of Work, Not located in 4CAQTF study area

POWER PLANTS: PUBLIC COMMENTS

Power Plants Public Comments

Comment	Mitigation Option
I have been concerned for many years about the air quality of the Four Corner's region because of the coal fired power plants in N.M. I attended two of the Four Corner's air quality forums in the past and was disturbed by their reports. As a nurse, I am especially concerned for the health of the Native Americans and other people who reside close to the power plants because of their incidence of lung disease. As a resident of La Plata canyon for 20+ years with a high mercury level, I am concerned about my own health and notice more air pollution, lack of visibility, every time I hike in the mountains. I believe for everyone's health, alternative sources of energy; e.g. solar, wind energy is a much better solution and would still serve as a revenue source to the Navajo nation. Desert Rock should not be built and the others should be phased out as planned many years ago or at least upgraded to standards that were set by the Clinton administration.	General Comment
We do NOT need another power plant in the 4 Corners. I notice the dirty air in this area all of the time and especially on weekends. Drive up from Albuquerque and see the air get dirtier. Also, go out from the 4 Corners and notice the beautiful blue skies as you progressively leave the area. I teach school and stress to my students they need to take care of the this planet earth because there is no spare earth. I would like to stress to everyone else that this needs to be done. Solar, wind and other energy sources should be used.	General Comment
It saddens me and concerns me for our children's futures and the native American leaders who think that this is progress and prosperity for their people. The leaders are once again selling out their people for the promise of temporary jobs and profits. How can we as a educated people agree to allow this plant in today's environment? Mercury in our children's blood and more carbons in the air are a horrible price to pay for short term gains in energy downstream. How can Governor Richards speak of the environment while he is silent on this issue. I will not be able to attend any public meetings and would appreciate my view forwarded if possible. I am a mother, grandmother and previous medical office manager. Most importantly, I am a voter.	General Comment
It breaks my heart to think that another coal fired plant may be added to our "pristine" 4 corners area. Even in Pagosa Springs we have some hazy smog some days, and when driving south and west of Farmington, that horrible yellow-brown cloud can be seen for miles! I was shocked to see that poisonous cloud in Monument valley, and northwest Utah. It's all pervasive now so I can't imagine what it will be like with more coal -spewing plants. We must use non polluting energy sources for the health of all of us!	General Comment

Comment	Mitigation Option
Desert Rock Energy LLC (Desert Rock) appreciates the opportunity to submit the following comments on the Four Corners Air Quality Task Force Draft Report. Desert Rock supports the Task Force's efforts to promote air quality mitigation in the Four Corners area. Desert Rock is committed to air quality mitigation, and has designed the proposed Desert Rock Facility to minimize impacts while providing needed electricity and additional economic development to the Navajo Nation. As detailed in the Draft Task Force Report, the proposed Desert Rock Facility is a 1,500 MW mine mouth power plant being developed by Sithe Global Power, Desert Rock Energy Company, and the Dinè Power Authority (an enterprise of the Navajo Nation). It is designed to burn low BTU, low sulfur subituminous Navajo coal. The plant will be located at an elevation of 5,415 feet. It will be one of the most efficient plants in the US, with two supercritical pulverized coal-fired boilers operating at a net heat rate of 8,983 Btu/kWh. The plant will be required to operate with very low emission rates, including 0.06 lb/MMBtu for both NOx and SO2 and 0.01 lb/MMBtu for filterable PM, all on a 24-hour average. The plant will also use dry cooling to reduce water consumption by 80 percent. EPA has stated that the Desert Rock Facility will have the lowest emission rates of any coal-fired project in the US. These emission rates will be even lower than emission rates associated with IGCC. Desert Rock is committed to engaging in regional air quality improvement initiatives. In fact, Desert Rock has already invested significant time and resources participating in such initiatives. Desert Rock has worked with the National Park Service, the National Forest Service, EPA, the Navajo National Environmental Protection Agency, and other governmental stakeholders to create a mitigation plan that will offset all SO2 emissions from the facility and further reduce mercury impacts. Below is a description of this regional effort: 1. Desert Rock Energy has agreed to a Voluntary Regional Air Quality Improvement Plan with the US EPA, US Forest Service, National Parks Service, and the Navajo Nation Environmental Protection Agency. 2. The Improvement Plan requires Desert Rock to reduce regional SO2 emission and visibility impacts by one of three (3) mechanisms: 1) Regional SO2 Control, 2) Regional NOx Control, or 3) Procurement and retirement of SO2 Allowances. a. Under an SO2 control-sponsored project, the implementation of this plan will result in a net improvement of the local environment. The plan, not only will totally offset the SO2 emissions of Desert Rock (3,315 tons of SO2), it will also remove an additional 330 tons of SO2 from the local atmosphere, for a total reduction of 110%. b. If an SO2 control project cannot be developed, Desert Rock may implement a NOx control-sponsored project which will remove NOx	General Comment

Comment	Mitigation Option
emissions in the region by 100% of Desert Rock NOx emissions plus approximately an additional 7500 tons. c. If Desert Rock is not able to invest in capital projects at other plants to reduce SO2 or NOx emissions, Desert Rock has reserved capital to purchase and retire up to $3,000,000 per year in SO2 allowances for the life of the project. The acquisition of these allowances is beyond those that are required under the Acid Rain program. 3. Mercury control of at least 80% will be achieved. Additional investments in Mercury control technology to reach a target of 90% control will be made subject to plan limitations. If the 90 % control target is met, it will reduce mercury emissions an additional 50 percent from approximately 160 lbs per year to approximately 80 lbs per year. 4. The local area will benefit from Desert Rock's annual environmental contributions that may be available subject to plan limitations. Such contributions could be used to advance the local environmental science and planning as well as sponsor projects that reduce greenhouse gas emissions, add further mercury control, increase monitoring, support the Four Corners Task Force, or contribute to any other environmental project determined to be of great value to the region. Desert Rock objects to the language in the Draft Report stating that "[t]he uncertainty [about the mitigation plan] involves how stakeholders can be assured the measures will actually happen." Desert Rock has made a public commitment to implement this mitigation plan and, in order to reassure all stakeholders of its commitment, is in the process of working with Federal agencies and the Navajo Nation to ensure that this mitigation plan is federally enforceable. The Desert Rock Facility will therefore be held accountable for fulfilling its mitigation commitments. In light of the mitigation plan, the Draft Report is incorrect in saying that "[w]hile the Desert Rock Energy Facility is using newer environmental emission control technology that on average have higher reduction efficiencies than existing facilities, the proposed power plant will still be adding substantial NO2, SO2, particulate, and other emissions to the Four Corners Area." It is quite likely that, because of the mitigation plan, either SO2 or NOx emissions in the area will actually be reduced. Although there will be a very small increase in emissions of other pollutants, the amounts are so small that the Plant will not have an appreciable impact on air quality in the Four Corners area. Discussion of CO2 Emissions Desert Rock believes that global climate change is a very serious	

Comment	Mitigation Option
issue and is committed to working with governments and industries to develop laws and policies - and most importantly, advanced technologies - that will reduce anthropogenic emissions of CO_2 and other greenhouse gases. Indeed, as discussed below, we are actively exploring options that may allow us to capture and sequester CO_2 emissions from the plant at some point in the future. We are concerned, however, about the discussion of CO_2 emissions in the Draft Report. The Report is designed to address air quality issues in the Four Corners area, and it is simply misleading to suggest that CO_2 is an air quality issue. CO_2 emissions in New York and New Delhi will have precisely the same impact on climate change in the Four Corners Region as CO_2 emissions from Desert Rock. By addressing CO_2 without making a clear distinction between air quality (which is largely a local and regional issue) and climate change (which is entirely a global issue), the Report will actually be misleading to many readers who are not fully informed about the nature of climate change. IGCC and Desert Rock The Draft Report includes a discussion of Integrated Gasification Combined Cycle (IGCC) technology that is not appropriate for the Desert Rock Facility. We are concerned that it will mislead readers into thinking that IGCC would be a better environmental choice for the Four Corners area, when this is simply not the case. The EPA Report cited in the Report does not address the issues involved in building an IGCC plant (or a modern supercritical pulverized coal plant) with the type of coal available in the Four Corners area or at an altitude anywhere near the elevation of the Desert Rock Facility. Not only technical experts with Desert Rock Energy, but other technical experts have concluded that there would be serious technical challenges involved in trying to operate an IGCC plant at a site like the Desert Rock Facility. The Report suggests that, at a minimum, Desert Rock should have been required to evaluate IGCC as part of the BACT process. Desert Rock did, in fact, evaluate the potential use of a range of modern coal technologies including IGCC. Nothing more would be learned by formally including such an evaluation in the BACT process. Desert Rock determined that the use of modern supercritical pulverized coal boilers is the best option, not only in terms of cost and reliability, but from an environmental standpoint as well. This technology is proven, reliable, and highly efficient and, in combination with an extensive array of pollution control equipment, will be a leader in reducing emissions from coal combustion. EPA has again stated that the Desert Rock Facility will have the lowest emissions rate of any coal-fired project in the US. As discussed below, there would be no material difference in emissions - including CO_2 and other green	

Comment	Mitigation Option
house gas emissions - with an IGCC plant at the Desert Rock site assuming current IGCC technology performance. Though IGCC is an evolving technology, IGCC does not currently meet the need for reliable and economical power production. There are only four operating coal-fired IGCC plants in the world, two in the United States both which use petroleum coke and not coal as the fuel source. Other IGCC projects in the US were built as small scale (less than 300 megawatts) demonstration projects with substantial government funding and some faced such severe operating problems that they never reached commercial operation. Even the facilities that did achieve commercial operation have not met projections for cost, efficiency, reliability and environmental performance. The "next generation" of IGCC plants, currently in development, with commercial operation dates planned in the 2011-2015 period, are in the 300-600 megawatt range. It remains to be seen if the next generation of IGCC plants will meet the cost and reliability targets needed to provide reliable, low cost power. There are also many engineering issues that remain to be solved in using low BTU high ash coals such as those found in New Mexico to fuel IGCC plants. Reliability - The IGCC units currently in operation have a poor reliability records. It remains to be seen if the next generation of IGCC plants will face similar reliability issues. The "integrated" part of IGCC refers to the integration of a gasifier and a combined cycle power plant to transform the coal into syngas and combust that syngas to produce electricity. This integration introduces numerous additional potential engineering points of failure and, as a result, there is a record of poor performance. Several of the IGCC units in operation have been able to reach the 80% reliability level but only after five to ten years of operation. In contrast, supercritical technology proposed for Desert Rock has a proven performance record of 90% or better, beginning in its first year of operation. Cost - Projections of life cycle capital and operating costs for IGCC plants in the 600 to 2,000 megawatt range are substantially higher than supercritical technology. These have demonstrated that the cost of a 1,500 megawatt IGCC plant is approximately 30-40% higher than a similarly-sized supercritical pulverized coal plant. Desert Rock would cost $1 billion more built using IGCC technology. Efficiency - The technology proposed for the Desert Rock Facility is highly efficient, meaning substantially less coal is used to produce the same amount of electricity with fewer emissions than older, conventional coal fired power plants. Desert Rock's proposed technology is also more efficient than current IGCC plants. For example, the technology proposed for the Desert Rock Facility is	

Comment	Mitigation Option
approximately 15% more efficient than the present IGCC facilities in Florida and Indiana, meaning it will use 15% less coal to produce a similar amount of electricity on an average annual basis. In comparison to recently filed air permit applications for the "next generation" IGCC plants, the Desert Rock Facility will have comparable efficiencies when the IGCC efficiency losses of operating at above 5,000 ft above sea level are taken in account. Emissions - Due to the high efficiency of the Desert Rock Facility's generating technology and the extensive array of pollution control equipment incorporated into its design, the plant's emission rates compare very favorably to existing IGCC units and are expected to be similar to the "next generation" IGCC plants. IGCC plants do not produce any less greenhouse gasses than a supercritical plant with similar efficiency Desert Rock is also designing the facility to have "future proofing" characteristics, which allow for augmentation of the initial extensive array of emissions control equipment and with more advanced control equipment when the new equipment is demonstrated to be commercially viable. Summary on IGCC - Desert Rock carefully considered all options available before concluding that supercritical pulverized coal technology is the best choice for the facility. The Desert Rock Facility's supercritical design helps to ensure a reliable power supply and lower fuel cost for customers, while being highly protective of public health and the environment. While IGCC is expected to become a viable large scale electric generation technology in the future, it currently lacks the reliability, efficiency, economics, and scale that supercritical technology provides with no material difference in emissions including greenhouse gases Carbon Sequestration and Desert Rock Sithe Global Power, LLC continues to study the technological and commercial implications of carbon capturing and sequestration (CCS) in power plant applications. With respect to the Desert Rock Facility, we have participated in numerous discussions with the Department of Energy, various national laboratories, and the major equipment suppliers to evaluate the technological feasibility and economic viability of a large scale CCS project. After extensive discussions, we have been unable to identify a commercially feasible solution. As of today, the major equipment suppliers are unwilling to offer performance guarantees for a large scale CCS project. In addition, an appropriate mechanism to recover the cost of implementation, including the cost of development, installation and operation, has not yet been implemented.	

Comment	Mitigation Option
As a result, Desert Rock is not in a position to incorporate CCS at this time. Desert Rock intends to continue to participate in the development of CCS and will consider the implementation of CCS once the technology and commercial framework are in place. The major equipment suppliers have an economic incentive to complete the development of the necessary technology. The Task Force can provide a great deal of assistance to help create and promote an appropriate commercial framework. Thank you for the opportunity to provide the above comments on the Draft Task Force Report. Desert Rock is again committed to air quality mitigation and appreciates the Task Force's efforts. If you have any questions or we can be of assistance, please let us know. Sincerely, Dirk Straussfeld Executive Vice President Desert Rock Energy Company, LLC Three Riverway Suite 1100 Houston, Texas 77056 Phone: (713) 499-1155 Fax: (713) 499-1167	
A Mitigation Option should be added for Nuclear technology. We should not assume that it is too controversial for consideration. The U.S. Nuclear Regulatory Commission is staffing up to consider up to 30 nuclear units in fiscal 2008. This was motivated by the Energy Policy Act of 2005, that has invigorated the power industry to come forward with new plans. A new NRC office has been created solely for licensing and oversight of new reactor activities, with a current staff of 240. The most activity for these units will be in the south and southeast, where utilities have on-going nuclear experience. NRC has streamlined their processes so standard design certifications would be approved, and the safety design hurdle would not be raised continually. Most of these applications will be active pump/valve cooling designs that meet the stringent safety requirements of standard design certifications. There is promise for a family of passive cooling reactors, where gravity/density differences provide equivalent cooling protection. These designs would be simpler and less expensive than current active pump designs. Much design work has been done, although there is not currently such a unit in operation. Nuclear plants have lower maintenance costs (about 1.7 cents per kwh, v.s. 3 - 5 cents for a fossil fuel units). Operating experience has advanced greatly over the 30 years since Three Mile Island, with plants running at 90% capacity -- up from 70% in the 1970s.	Proposed Power Plant - Desert Rock Energy Facility

Comment	Mitigation Option
Benefits: Zero air emissions impact; No carbon footprint; cost effective electricity generation; foster high technology employment basis in Four Corners; proximity to future Nevada spent fuel storage site Tradeoffs: Negative public opinion; spent fuel containment Reference: Energybiz magazine Vol. 4, Issue 3 (May 07, June 07) "Agency Gets Ready for Nuclear Renaissance" -- "Repackaging the Nuclear Option" -- "GE Gears Up"	
I feel this (and perhaps one or two other power plants options) should be incorporated by reference into the monitoring section. There is a lot of good writing here.	Negotiated Agreements in Prevention of Significant Deterioration (PSD) Permits
The monitoring of degrading power plants deserves dual attention; both in this section and in the monitoring section for emphasis.	Negotiated Agreements in Prevention of Significant Deterioration (PSD) Permits
The Electric Power Research Institute (EPRI) today announced the beginning of a new project to study the feasibility of concentrating solar power in New Mexico. Unlike conventional flat-plate solar or photovoltaic panels, concentrating solar power (CSP) uses reflectors to concentrate the heat and generate electricity more efficiently. There are four utility-sized CSP plants in the U.S. today; one in Nevada and three in California. Initiated by New Mexico utility PNM and with subsequent interest from other regional utilities, the project will be directed and managed by EPRI. PNM has expressed interest in building a CSP plant in New Mexico by 2010. The feasibility study for a power plant of the 50-500 megawatt (MW) size range is expected to be finished by the end of 2007. The Four Corners area is one of the best areas for solar energy production in the United States and would be an ideal location for a new solar energy plant. For example, in Farmington, NM a flat-plate collector on a fixed-mount facing south at a fixed tilt equal to latitude, sees an avg. of 6.3 hours of full sun. The Solar plant could help New Mexico meet renewable	Utility-Scale Photovoltaic Plants

Comment	Mitigation Option
energy portfolio standards. San Juan County also has a renewable energy school focusing on solar energy system design and installation. The plant could potentially be an educational/technical resource for the college.	
I would emphatically like to see this option included in the final report.	Reorganization of EPA Regions
The need for these studies is obvious and the cost should be passed on to the utilities (and therefore the customers). However, even if these new studies find a significantly negative relationship between chronic respiratory disease and air pollutants, we already have proof that air pollutants increase the incidence of asthma. This mitigation option should include plans to utilize the study results for actively engaging policy-makers and changing regulations and enforcement, especially in geographic hot spots.	Chronic Respiratory Disease Study for the Four Corners area to determine relationship between Air Pollutants from Power Plants and Respiratory Health Effects