Utah Attorney General's Office
Memorandum

To: Utah Air Quality Board

From: Fred Nelson, Counsel to Board

Re: Motions in IPP/Sevier Power approval order appeals.

Date: March 21, 2007

Attached you will find the pleadings that will be considered for decision at the Air Quality Board Meeting on April 4, 2007. Additional replies may be filed by March 26 (a date established by the Board) and they will be forwarded separately.

In part, because of the volume of the materials and use of numerous legal terms, I provide the following information in an attempt to facilitate your review.

Sierra Club has challenged the issuance by the Executive Secretary of two approval orders to construct coal-fired power plants, one for a third unit at the IPP plant near Delta, and one for a power plant to be constructed near Fillmore by the Sevier Power Company. The appeals are called "Requests for Agency Action" under the Utah Administrative Procedures Act. The Utah Air Quality Board set the hearing dates for those challenges to be September (for Sevier Power) and November (for IPP Unit 3). The Board also established the April meeting as a time for hearing initial "dispositive" motions in both appeals. Dispositive motions are allowed under the rules, in part, to potentially simplify and resolve matters that do not need a full evidentiary hearing. A dispositive motion is an assertion by a party that an issue can be resolved without an evidentiary hearing. It can take the form of a Motion to Dismiss (ie. no jurisdiction), or a Motion for Judgment on the Pleadings (there are no fact issues and the decision can be made by only considering the statements and allegations made in the Request for Agency Action), or a Motion for Summary Judgment (supporting affidavits with uncontested facts that can justify a decision without an evidentiary hearing).

In this case various parties have filed Motions for Judgment on the Pleadings and Motions for Summary Judgment. In considering a Motion for Judgment on the Pleadings the Board should assume as true the facts as stated in the Request for Agency Action and determine whether it can rule on each presented issue without an evidentiary hearing. For a Motion for Summary Judgment, the Board should consider the presented information to determine whether there are uncontested facts upon which the decision can be based, with no evidentiary hearing necessary. The granting of a Motion for Judgment on the Pleadings or a Motion for Summary Judgment means the Board would be making a decision on the issue now and, therefore, would not further consider that issue at its September/November hearings. A decision to deny a Motion for Judgment on the Pleadings or Motion for Summary Judgment would not constitute a determination, one

way or the other, as to the validity of a claim, it would mean the issue would go to an evidentiary hearing.

All parties have submitted dispositive motions on some issues raised or requested to be part of Sierra Club's Requests for Agency Action. The motions are attached in Sections A, B, and C. Much of the attached information and argument is duplicative because the issues are common to both cases. I recommend the Board, at its April 4th meeting, consider first the Motions of Sierra Club in Section A, because if those motions are granted, the approval orders may be considered revoked and the matters would be remanded back to the Executive Secretary. In that circumstance, it would not be necessary for the Board to consider the Motions filed by IPP, Sevier Power, or the Executive Secretary. If the Board denies Sierra Club's motions, the Board would then consider the motions attached in Section B.

Under Section A, you have the following documents:

Tab 1. Sierra Club's Motions to Amend its Request for Agency Action in both the IPP and Sevier Power appeals to add a claim that the approval orders have expired because construction has not taken place within 18 months of the issuance of the approval orders.

Tab 2. IPP, Sevier Power, and Executive Secretary Opposition memos to the Motions to Amend the Requests for Agency Action.

Tab 3. Sierra Club's Motions for Summary Judgment in both cases based on the 18 month provision issue that the approval orders be determined no longer valid, and, further, in the IPP case, that the Executive Secretary did not follow the rules in approving a modification to the approval order changing the approved boiler technology.

Tab 4. IPP, Sevier Power, and Executive Secretary Opposition memos to Sierra Clubs' Motions for Summary Judgment.

The primary determination to be made under the pleadings in Section A is whether to allow Sierra Club to add the claim concerning the 18 month provision and whether to grant judgment to Sierra Club in both cases based on that claim.

Section B contains Motions for Judgment on the Pleadings filed by IPP, Sevier Power, and the Executive Secretary, on two issues common to both appeals. The two issues are 1) whether the Executive Secretary erred by not considering the technology referred to as IGCC in determining Best Available Control Technology, and 2) whether the Executive Secretary erred by not considering carbon dioxide and greenhouse gases in issuance of the approval orders. IPP also moves for judgment on the pleadings on a third issue, whether the Executive Secretary was required to consider specific coal chemistry information different from the coal information provided.

Section B includes:

Tab 1. Motions for Judgment on the Pleadings by IPP, Sevier Power, and the Executive Secretary.

Tab 2. Sierra Club's Consolidated Opposition to Motions for Judgment on the Pleadings.

The determination to be made by the Board under the Section B is whether to grant or deny all or part of each motion.

Section C is Sierra Club's Protective Motion under Utah Rules of Civil Procedure 56(f) that requests that if the Board treats any of the Motions for Judgment on the Pleadings as Motions for Summary Judgment, Sierra Club be given further time to do discovery before the Board rules on the motion. As explained above, a Motion for Summary Judgment requires submission of evidence and a party countering such a motion must respond with evidence demonstrating there are issues of fact that require that the issue should go to hearing.

If you have any questions, please call (801-366-0285). I would remind each Board member that this is an adjudicative proceeding and that you may not participate in dialog or conversation with or receive information from any of the parties (Sierra Club, IPP, Sevier Power, and the Executive Secretary) outside the forum of a Board meeting where all parties are given the opportunity to be present.

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BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – the Sevier	:	
Power Company 270 MW Coal-Fired	:	MOTION FOR LEAVE
Power Plant, Sevier County	:	TO AMEND REQUEST FOR
Project Code: N0327-010	:	AGENCY ACTION
DAQE-AN2529001-04	:	

MOTION FOR LEAVE TO AMEND REQUEST FOR AGENCY ACTION

The Utah Chapter of the Sierra Club ("Sierra Club") respectfully moves to amend its Request For Agency Action. In support of its motion, Sierra Club submits its Memorandum in Support of Motion to Amend Request for Agency Action and its First Amended Request for Agency Action.

Dated: February 16, 2007

__/s/_____
JORO WALKER
DAVID BECKER
Attorneys for Utah Chapter of the Sierra Club

CERTIFICATE OF SERVICE

I hereby certify that on this 16th day of February 2007, I caused a copy of the foregoing Motion for Leave to Amend Request for Agency Action to be emailed to the following:

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BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – the Sevier Power Company 270 MW Coal-Fired Power Plant, Sevier County Project Code: N2529-001 DAQE-AN2529001-04	:	FIRST AMENDED REQUEST FOR AGENCY ACTION

FIRST AMENDED REQUEST FOR AGENCY ACTION

Pursuant to Utah Administrative Code R307-103-3(1) and Utah Code § 63-46b-3(3), the Utah Chapter of the Sierra Club ("Sierra Club") hereby files its First Amended Request for Agency Action with Richard W. Sprott, Executive Secretary of the Utah Air Quality Board. The Sierra Club seeks review of the October 12, 2004 decision by the Utah Division of Air Quality and the Executive Secretary (collectively "UDAQ") to issue an Approval Order (AO) allowing the Sevier Power Company[1] to construct and operate a 270 MW coal-fired power plant in Sigurd, Sevier County, Utah (DAQE-AN2529001-04)(Project Code: N2529-001). Pursuant to Utah Admin. Code R307-103-3(2), R307-103-6(2)(c), and R307-103-3, the Sierra Club relies on the Statement of Standing/Petition to Intervene previously submitted with its Request for Agency Action.

I. Permit Number and Date of Mailing

As mentioned above, Sierra Club is contesting the Approval Order signed by Richard W. Sprott, Executive Secretary of the Utah Air Quality Board, on October 12, 2004 to authorize the construction and operation of the Sevier Power Company 270 MW Coal-Fired Power Plant in Sigurd, Utah (DAQE-AN2529001-04)(Project Code: N2529-001). According to UDAQ, the date of mailing of the AO is October 12, 2004.

[1] According to UDAQ, NEVCO Energy Company, LLC, is the parent company of the Sevier Power Company.

II. Statement of Legal Authority and Jurisdiction

Sierra Club brings this Request for Agency Action pursuant to Utah Admin. Code R307-103-3(1), which states that "[i]nitial orders and notices of violation, as described in R307-103-2(1)[2], may be contested by filing a written Request for Agency Action to the Executive Secretary, Air Quality Board, Division of Air Quality . . . " R307-103-3(1). Utah Code 63-46b-3(3) specifies the content of this Request for Agency Action.

III. Statement of Facts and Reasons

A. Statement of Facts

On April 1, 2003, Sevier Power Company submitted a prevention of significant deterioration (PSD) permit application and its Notice of Intent (NOI) to construct a 270 megawatt (MW) coal-fired power plant near Sigurd, Utah. On September 10, 2003, Sevier Power Company submitted a revised PSD permit application and NOI.

The Sevier Power Company facility has the potential to emit 100 or more tons per year of carbon monoxide (CO), nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulate matter with an aerodynamic diameter equal to or less than 10 micrometers (PM-10). Thus, the proposed coal-fired power plant is considered a new major source for those pollutants. The area in which the facility is to be located is currently designated as having attainment status for all pollutants. Therefore, the facility is required to meet the provisions of Utah's PSD regulation, Utah Admin. Code R307-405, in addition to other applicable provisions of the Utah Admin. Code, including the requirements of a Notice of Intent and Approval Order established by Utah Admin. Code R307-401.

The facility has the potential to emit at least 10 tons per year of one hazardous air pollutant (HAP), specifically hydrogen chloride (HCl). Therefore, the facility is considered to be a major source of HAPs and subject to Utah's provisions for case-by-case determination of maximum achievable control technology (MACT) limits for HAPs, pursuant to Utah Admin. Code R307-214-2.

Because the facility will be an electric utility steam generating unit capable of combusting more than 73 MW heat input of coal, the facility is subject to the New Source Performance Standards (NSPS) of 40 C.F.R. Part 60, Subpart Da, which Utah has incorporated by reference into state regulation at Utah Admin. Code R307-210-1.

Sierra Club has been involved throughout the permitting process for the proposed Sevier Power Company power plant. On October 17, 2003, Sierra Club submitted extensive comments on the proposed project in advance of the public comment period, detailing the permitting requirements pertaining to the permit application. The Sierra Club participated in a UDAQ public hearing held in Richfield, Utah on March 18, 2004.

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[2] Utah Admin. Code R307-103-2(1) defines an initial order as, *inter alia*, "approval, denial, termination, modification, revocation, reissuance or renewal of permits, plans, or approval orders." Utah Admin. Code R307-103-2(1)(a).

In addition, on April 9, 2004 and within the designated public comment period, Sierra Club submitted extensive comments on the UDAQ Intent to Approve the Sevier Power Company permit. Following the re-opening of the comment period, Sierra Club supplemented its April 9, 2004 comments with additional comments dated June 30, 2004 and July 16, 2004.

On October 12, 2004, Richard W. Sprott, Executive Secretary of the Utah Air Quality Board, signed an AO authorizing construction and operation of the proposed Sevier Power Company 270 MW circulating fluidized bed (CFB) coal-fired power plant. According to the Approval Order, the operation of the power plant would allow air emissions increases, in tons per year, of: 177.4 of PM-10; 1066.6 of NO_x; 233.9 of SO_2; 1278.6 of CO, and 53.4 of VOCs, and 24.7 of HAPs. With the AO, UDAQ released a memorandum titled "Response to Comments received on Sevier Power Company," authored by John D. Jenks, Environmental Engineer.

B. Statement of Reasons

As set forth below and in Sierra Club's comments, UDAQ's approval of Sevier Power Company PSD permit fails to comply with the Clean Air Act, the Utah Air Conservation Act, and the Utah Administrative Code. Sierra Club hereby incorporates and references its comments dated October 17, 2003, April 9, 2004, June 30, 2004, and July 16, 2004, and the documents submitted in support of those comments.

In addition, the Sierra Club sets forth the basis for its request for agency action below:

1. UDAQ Failed to Address Carbon Dioxide and Other Greenhouse Gas Emissions.

The Sevier Power Company estimates that the proposed power plant has the potential to emit 2.2 million tons of carbon dioxide (CO_2) and 1,640 tons of nitrous oxide (N_2O) each year. Both CO_2 and N_2O are greenhouse gases. N_2O has a global warming potential 296 times that of CO_2. N_2O is of significant concern because circulating fluidized bed boilers, such as the one being proposed by the Sevier Power Company, emit significantly more N_2O than conventional pulverized coal boilers.

UDAQ did not address these or other greenhouse emissions during the permitting process based on its belief that "UDAQ has no legal or regulatory authority to limit or control these emissions." Response to Comments at 29 (#83). However, UDAQ notes that "greenhouse gas emissions are potentially an area of concern." Id. Pursuant to the Clean Air Act and Utah Air Quality Act and its implementing rules, the State of Utah has the legal obligation to regulate greenhouse gases. Further, pursuant to the definition of "best available control technology" (BACT), Utah Admin. Code R307-101-2, Utah is required to consider other environmental impacts, such as greenhouse gas emissions, when determining BACT for a facility. Because UDAQ did not undertake this consideration, the Sevier Power Company permit should be declared illegal, should be

rescinded, and/or should be remanded to UDAQ to properly consider and regulate these pollutants in a PSD permit.

2. UDAQ Failed to Consider Adequately Integrated Gasification Combined Cycle in its BACT Determination for Sevier Power Company Facility.

Integrated Gasification Combined Cycle (IGCC) is a method of producing electricity by gasifying the coal, removing pollutants – including greenhouse gases – before combustion, and then burning the "clean" syngas in a modified combined cycle gas-fired power plant. IGCC is an available, demonstrated clean coal combustion technology with significant emission reduction benefits. As such, UDAQ is required to evaluate this technology comprehensively as part of its BACT analysis. To justify its failure to undertake this analysis, UDAQ suggests that "BACT is used as a control technology after selection of the process to be so controlled." Response to Comments at 30 (#84). UDAQ concludes that requiring the consideration of IGCC as part of the BACT analysis is "redefining the source." Id.

UDAQ's legal conclusion regarding the requirements of the BACT analysis is erroneous. Consideration of inherently lower emitting power production processes and techniques such as IGCC is required pursuant to Utah Admin. Code R307-101-2, which defines BACT. As the rule makes clear, consideration of the process design is a necessary part of the BACT analysis. Sevier Power Company did not consider IGCC in its BACT analysis for its proposed power plant, and UDAQ did not evaluate IGCC in its BACT review or determination. Therefore, the Sevier Power Company permit should be declared illegal, should be rescinded, and/or remanded to the agency for proper BACT analysis.

3. UDAQ Failed to Provide Adequate Justification for Not Requiring Sevier Power Company to Meet the Most Stringent NO_x BACT Limits Proposed or Required for Other CFB Boilers.

UDAQ determined that a NO_x emission limit of 0.10 lb/MMBtu, 24-hour rolling average, represents BACT for the proposed CFB boiler. However, NO_x BACT emissions limits for other power plants, including several proposed CFB boilers, are more stringent that the rate proposed for the power plant. Selective Catalytic Reduction (SCR) has been determined to be the Best Available Control Technology for NO_x for most recently permitted coal-fired power plants. Yet, UDAQ failed to provide a reasoned justification for not requiring or evaluating more stringent NO_x emission limits, or installation of SCR, in its BACT determination. Therefore, the Sevier Power Company AO should be declared illegal, should be rescinded, and/or remanded to the agency for proper BACT analysis.

4. UDAQ Failed to Consider Sufficiently Activated Carbon Injection for Control of Mercury Emissions from Sevier Power Company Plant in its MACT Determination.

UDAQ did not perform an adequate analysis of the case-by-case mercury MACT. UDAQ did not require consideration of activated carbon injection for control of mercury in its case-by-case MACT analysis. It appears that UDAQ did not consider activated carbon injection to be an available technology and thus did not evaluate this technology in its MACT analysis. However, as sworn testimony and supporting documents relied on or provided at an April 20, 2004 hearing on the Roundup Facility before the Montana Board of Environmental Review establishes, activated carbon injection is an available technology for mercury control from coal-fired power plants. Thus, UDAQ erroneously failed to consider carbon injection in the mercury MACT analysis and the Sevier Power Company AO should be declared illegal, should be rescinded, and/or should be remanded to the agency for proper MACT analysis.

5. UDAQ Failed to Require Continuous Opacity Monitoring to Measure Compliance with the Visible Emissions BACT Limit.

UDAQ required that visible emissions from any stationary point at proposed plant shall not exceed 10 percent opacity. Condition 12 of the AO and Response to Comments at 31 (#88). UDAQ specified that opacity observations shall be conducted according to 40 C.F.R. Part 60, Appendix A, Method 9, which is a manual method of measuring opacity requiring a certified opacity inspector to be present. No frequency for Method 9 observations is specified. Such infrequent monitoring is not sufficient to ensure continuous compliance with the opacity limit. UDAQ must require use of a continuous opacity monitoring system (COMS) to ensure continuous compliance with the visible emissions BACT limit as stated in 40 C.F.R. §§ 60.47a through 60.49a. Because UDAQ did not, the Sevier Power Company AO should be declared illegal, should be rescinded, and/or should be remanded to the agency to ensure continuous compliance with the visible emission limit.

6. UDAQ's Justification for Determining that the Proposed Plant Would Not Cause or Contribute to a Violation of the PM-10 National Ambient Air Quality Standards (NAAQS) is Flawed.

UDAQ concluded that "the proposed construction of the new power plant would not cause an exceedance of the NAAQS for PM-10; nor would it significantly contribute to any model predicted exceedances of the NAAQS in the Sevier Valley." Response to Comments at 6 (#13). However, there is no legal basis in Utah regulations or law for the finding that the proposed power plant would not contribute to a violation of the PM-10 NAAQS merely because it does not contribute "significantly" to the violations of the PM-10 NAAQS that were modeled by the Sevier Power Company. In other words, UDAQ cannot rely on a finding that the plant will not "significantly" contribute to NAAQS violations to suggest that the plant will not "contribute" to these violations. Because UDAQ's reasoning is flawed, the agency is prohibited from approving the

Sevier Power Company AO pursuant to Utah Admin. Code R307-401-6(2) and R307-405-6(2)(a)(i)(A).

Further, there is insufficient evidence in the record to support UDAQ's calculation of whether the proposed facility would cause or contribute to a violation of the PM-10 NAAQS. In particular, UDAQ failed to justify adequately the elimination of Western Clay Company of Aurora from the analysis, failed to consider the maximum, 24-hour average emissions from the two gypsum plants in the area, and failed to address sufficiently all fugitive sources of PM-10 emissions including dust from agricultural sources.

UDAQ also failed to recognize the existing modeled violations of the PM-10 NAAQS. Indeed, this information was not included in the ITA, the public notice, or in the UDAQ New Source Plan Review for the Sevier Power Company proposed power plant. Further, UDAQ has not stated any future plans to designate the area as nonattainment or to adopt a control strategy for the area to bring the area into attainment. Although one of the two gypsum plants in the valley has shut down, UDAQ did not revoke the gypsum plant permit to ensure that the plant could no longer contribute to unhealthy air quality. In fact, UDAQ admits the gypsum plant was only temporarily shut down, and that the plant could restart operations at any time under its existing AO. Response to Comments at 21 (#57).

Moreover, UDAQ failed to justify the use of the second highest PM-10 monitored value as representative of PM-10 background concentrations. UDAQ attempts to justify the elimination of the highest 24-hour concentration by suggesting that "[t]he combination of high winds and fire smoke on the highest monitored day suggested that the monitoring sample was a rare event, and not necessarily suitable for use in the analysis as a indicator of normal worst-case background levels for the area." Response to Comments at 20-21 (#55). Yet, "normal worst-case background levels" is a contradiction in terms. UDAQ's decision lacked sufficient analysis to show that the true cause of the highest monitored PM-10 value or to show that such occurrences are rare for the area.

In summary, UDAQ cannot support its decision to issue the AO in light of the results of air quality modeling that establish existing violations of the PM-10 NAAQS in the area. Nor can the agency defend its decision to equate a finding of non-significant contribution with a finding that the proposed facility does not contribute at all to PM-10 NAAQS violations. Further, UDAQ's determination of project's impact on PM-10 concentrations is not sufficiently supported in the record. Therefore, the Sevier Power Company AO should be declared illegal, should be rescinded, and/or should be remanded to the agency for compliance with the PM-10 NAAQS requirements.

7. UDAQ Failed to Require Sufficient Analysis of the Impacts of the Sevier Power Company Facility on Visibility, Soils, and Vegetation.

Pursuant to Utah Admin. Code R307-405-6(2)(a)(i)(D), UDAQ must require a PSD permit applicant to provide a full and complete analysis of "the impairment to

visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification." *See also* 40 C.F.R. § 52.21(o)(1) & (2). In response to comments raised about the necessity for such an analysis, UDAQ responded that: 1) the soil and vegetation analysis was conducted by Red Elk Consulting, Response to Comments at 7 (#17); 2) UDAQ reviewed this analysis and "feels it satisfies the requirement of this rule," Response to Comments at 17 (#43) and; 3) "there is no regulatory requirement under the PSD regulation for assessing visibility impacts in Class II areas such as Sevier Valley." Response to Comments at 28 (#80).

However, identifying a consultant does not ensure that a full and complete analysis of the impact to soils and vegetation has occurred. Moreover, the public should have some opportunity to review the soils and vegetation analysis to ensure compliance with the rule. And, Utah Admin Code R307-405-6(2)(a)(i)(D) explicitly requires the Sevier Power Company to provide an analysis of impairment to visibility in Class II areas, such as Sevier Valley. Accordingly, UDAQ has failed to demonstrate that a full and complete analysis of the impairment to visibility, soils, and vegetation was provided by the Sevier Power Company. Therefore, the relevant AO should be declared illegal, should be rescinded, and/or should be remanded to the agency for proper soils, vegetation, and Class II visibility analysis.

8. UDAQ Illegally Exempted the Proposed Facility from a Cumulative Class I Increment Analysis.

UDAQ did not require a cumulative Class I increment (also known as "maximum allowable increase") analysis from the Sevier Power Company. This decision was based on a policy that, if a source's impact on a Class I areas is less than a Class I "Significant Impact Level" (SIL), "there is no technical grounds for a cumulative effects analysis." Response to Comments at 33 (#95). UDAQ indicates that this approach has been adopted as a state policy and is endorsed by the EPA – Region VIII Modeler and the National Park Service Air Quality Modeler in Denver. Id. However, use of SILs is not authorized in any state or federal law or regulation. UDAQ also has never provided the public with any written policy regarding this approach to a cumulative Class I increment analysis. Indeed, such an approach directly contradicts Utah Admin. Code R307-405-6(2), which provides in pertinent part:

> Every new major source. . . must be reviewed by the Executive Secretary to determine the air quality impact of the source to include a determination whether the source will cause **or contribute to** a violation of the maximum allowable increases or the NAAQS in any area. The determination of air quality impact will be made as of the source's projected startup date. **Such determination shall take into account all allowable emissions of approved sources or modifications whether constructed or not, and, to the extent practicable, the cumulative effect on air quality of all sources and growth in the affected area.**

Emphasis added.

The Sevier Power Company attempted to comply with this regulation by submitting a cumulative Class I increment analysis in its September 10, 2003 PSD permit application and NOI, although the analysis was faulty and incomplete as discussed further below. However, UDAQ never presented this analysis in its ITA or its New Source Plan Review for the proposed power plant, based on the state's claim that no such cumulative analysis was required. Because UDAQ failed to require the Sevier Power Company to comply with state regulation requiring a cumulative Class I increment, the relevant AO should be declared illegal, should be rescinded, and/or should be remanded to the agency for proper Class I increment analysis.

9. The Proposed Facility Will Contribute to Class I SO_2 Increment Violations at Capitol Reef National Park.

UDAQ violated Utah regulations in issuing the AO because, as currently permitted, the Sevier Power Company plant will contribute to violations of the Class I SO_2 increment (otherwise known as "maximum allowable increase") in Capitol Reef National Park. Although the company submitted a **cumulative** Class I SO_2 increment analysis with its September 10, 2003 PSD permit application and NOI that did not indicate any Class I increment violations, its cumulative analysis was flawed and incomplete. Most significantly, the Sevier Power Company failed to model existing sources at their maximum actual 3-hour average and 24-hour average SO_2 emission rates. This approach is not consistent with the Guidelines on Air Quality Models, incorporated by reference into Utah regulations at Utah Admin. Code R307-410-2 and fails to protect sufficiently Class I airsheds including Capitol Reef National Park. The Sevier Power Company also failed to include all increment consuming emissions in its analysis, including the emissions of other proposed new facilities such as the proposed Unit #3 of the Intermountain Power Plant.

The National Park Service, in the context of reviewing the Notice of Intent to Construct for Unit #3 at the Intermountain Power Plant, conducted a more accurate Class I SO_2 increment analysis that shows that **existing** sources in Utah are causing violations of the 3-hour average Class I increment in Capitol Reef National Park. The Park Service presented this analysis to UDAQ electronically before or in November of 2003. On March 25, 2004, the National Park Service submitted a letter to UDAQ that provided, among other things, the Park Service's formal findings that the three-hour average SO_2 increment was being violated by existing sources in Utah at Capitol Reef National Park.

Sevier Power Company's modeling analysis showed that the proposed facility would affect 3-hour average SO_2 concentrations at Capitol Reef National Park. *See* Table 7-8 of Sevier Power Company's PSD Permit Application (September 10, 2003). Because the facility would contribute to the increment violations at Capitol Reef National Park (shown by the National Park Service's modeling analysis), UDAQ is prohibited from issuing the AO. *See* Utah Admin. Code R307-401-6(2), R307-405-6(2)(a)(i)(A) and R307-405-6(2)(c).

As discussed above, state or federal law does not support the use of SILs to find that Sevier Power Company would not contribute to the increment violation at Capitol Reef National Park. Further, EPA policy states that, in an area with an existing increment violation, **any** impact is significant. *E.g., see* April 12, 2002 letter to Terry O'Clair, North Dakota Department of Health, from Richard R. Long, EPA Region VIII. In addition, EPA's longstanding interpretation of the statutory and regulatory provisions for the PSD increments clearly mandate that, in an area with existing PSD increment violations, the violations "must be entirely corrected before PSD sources which affect the area can be approved." 45 Fed.Reg. 52678 (August 7, 1980).

Thus, because the proposed facility will contribute to violations of the Class I SO_2 increment in Capitol Reef National Park, the relevant AO should be declared illegal, should be rescinded, and/or should be remanded to the agency for proper analysis of SO_2 increment violations and for compliance with emission offset requirements.

10. The Approval Order for the Proposed Plant is Now Invalid Because Construction Did Not Commence Within 18 Months of the Approval Order, and the Approval Order Has Automatically Expired.

The Executive Secretary signed the Approval Order for the proposed plant on October 12, 2004. The Utah PSD regulations provide, under "Source Obligations," that "the provisions of 40 C.F.R. 52.21(r), effective March 3, 2003, are hereby incorporated by reference." R307-405-19(1). That federal regulation, in turn, provides that:

> Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified.
>
> 40 C.F.R. 52.21(r)(2).

The AO is also subject to this federal regulation, which has been in effect since at least 1975, by the terms of the AO itself. The AO expressly provides that "[t]his AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including R307." AO at 12.

Twenty-eight months have now passed since the Executive Secretary signed the AO for the proposed plant. Upon information and belief, construction has not yet commenced, notwithstanding that there has been no stay of the AO since it was approved. The Administrative Record for this AO, which UDAQ compiled and made available to the parties for duplication on February 6, 2007, and obtained in electronic format by Sierra Club on February 15, 2007, shows that there has been no extension of the 18-month period for automatic invalidation of the AO granted to Sevier Power Company.

Because more than 18 months have passed since the AO was issued on October 12, 2004, and no extension has been granted, the AO is now invalid, having expired automatically on or about April 12, 2006. Accordingly, Sevier Power Company must submit a new NOI to DAQ and re-initiate the AO process for approval to construct the proposed plant.

In addition, the terms of the AO itself provide that "[i]f construction and/or installation has not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11." AO at 5. R307-401-11, now renumbered as R307-401-18, provides that

> Approval orders issued by the executive secretary in accordance with the provisions of R307-401 shall be reviewed eighteen months after the date of issuance to determine the status of construction, installation, modification, relocation or establishment. If a continuous program of construction, installation, modification, relocation or establishment is not proceeding, the executive secretary may revoke the approval order.

The Administrative Record also reflects that Sevier Power Company did not notify the Executive Secretary of the status of the project as required under the terms of the permit, and that the Executive Secretary did not conduct the review required by regulation in April 2006. This review was mandatory under the regulations. The lack of a review prevented the DAQ from assessing whether any changed circumstances warranted revocation of the AO after eighteen months in which construction had not begun. The absence of that review, coupled with the automatic expiration of the approval to construct under R307-405-19(1) and corresponding source obligations in the federal regulations, require that Sevier Power Company now submit a new NOI to DAQ to obtain approval to construct the proposed plant.

D. Request For Relief

Based on the above, the Sierra Club respectfully requests that the Air Quality Board declare the AO for the proposed Sevier Power Company facility illegal, revoke the AO for the plant, and/or remand the AO to UDAQ with instructions that the agency comply with the law and undertake or require the proper analysis as part of the permit and permitting process.

Dated: February 16, 2007

__/s/_____
DAVID BECKER
JORO WALKER
Attorneys for Sierra Club

CERTIFICATE OF SERVICE

I hereby certify that on this 16th day of February 2007, I caused a copy of the foregoing First Amended Request for Agency Action to be emailed to the following:

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BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – PSD Major	:	
Modification to Add New Unit 3 at	:	MOTION FOR LEAVE
Intermountain Power Generating	:	TO AMEND REQUEST FOR
Station, Millard County, Utah	:	AGENCY ACTION
Project Code: N0327-010	:	
DAQE-AN0327010-04	:	

MOTION FOR LEAVE TO AMEND REQUEST FOR AGENCY ACTION

The Utah Chapter of the Sierra Club ("Sierra Club") respectfully moves to amend its First Amended Request For Agency Action. In support of its motion, Sierra Club submits its Memorandum in Support of Motion to Amend Request for Agency Action and its Second Amended Request for Agency Action.

Dated: February 16, 2007

_____
JORO WALKER
DAVID BECKER
Attorneys for Utah Chapter of the Sierra Club

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I hereby certify that on this 16th day of February 2007, I caused a copy of the foregoing Motion for Leave to Amend Request for Agency Action to be emailed to the following:

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BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – the Sevier	:	
Power Company 270 MW Coal-Fired	:	MOTION FOR LEAVE
Power Plant, Sevier County	:	TO AMEND REQUEST FOR
Project Code: N0327-010	:	AGENCY ACTION
DAQE-AN2529001-04	:	

MOTION FOR LEAVE TO AMEND REQUEST FOR AGENCY ACTION

The Utah Chapter of the Sierra Club ("Sierra Club") respectfully moves to amend its Request For Agency Action. In support of its motion, Sierra Club submits its Memorandum in Support of Motion to Amend Request for Agency Action and its First Amended Request for Agency Action.

Dated: February 16, 2007

__/s/_____
JORO WALKER
DAVID BECKER
Attorneys for Utah Chapter of the Sierra Club

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BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station, Millard County, Utah Project Code: N0327-010 DAQE-AN0327010-04	:	MEMORANDUM IN SUPPORT OF MOTION FOR LEAVE TO AMEND REQUEST FOR AGENCY ACTION

MEMORANDUM IN SUPPORT OF
MOTION FOR LEAVE TO AMEND REQUEST FOR AGENCY ACTION

The Utah Chapter of the Sierra Club ("Sierra Club") respectfully submits this memorandum in support of its motion to amend its First Amended Request For Agency Action. In conjunction with its motion, Sierra Club submits to the Air Quality Board ("Board") its Second Amended Request For Agency Action.

The Second Amended Request For Agency Action amends the Sierra Club's First Amended Request For Agency Action by dropping references to the Grand Canyon Trust, which has now withdrawn from this matter, and corrects the errata in Statement of Reasons # 20 which were described in Sierra Club's submission on January 3, 2007.

In addition, the Second Amended Request for Agency Action adds an additional claim, which appears as Statement of Reasons # 22. After review of the administrative record, which was produced by the Division of Air Quality ("DAQ") on February 6,

2007, and of which the parties obtained copies on February 15, 2006, it became apparent that the Approval Order ("AO") issued for Unit 3 has expired by operation of federal and state regulations when 18 months had passed without commencement of construction. For this reason, and as described in Statement of Reasons # 22 in the Second Amended Request for Agency Action, the Board must declare the AO invalid.

In court, Utah Rule of Civil Procedure 15(a) applies to motions to amend pleadings. In this matter, the DAQ has already responded to Sierra Club's First Amended Request for Agency Action. In these circumstances, Rule 15(a) states that "a party may amend his pleading only by leave of court or by written consent of the adverse party; and leave shall be freely given when justice so requires."[1] Based on this rule, Sierra Club seeks the Board's permission to amend its request for agency action.

The Utah Supreme Court has "consistently encouraged liberal treatment of motions to amend a pleading as long as justice is furthered, and not hindered, by the amendment, so as to allow examination into and settlement of all issues bearing upon the controversy, [while] safeguard[ing] the rights of the other party to have a reasonable time to meet a new issue."[2] Allowing amendment of a complaint – or, in this matter, the request for agency action – is particularly appropriate where the amendment is presented well before trial, and the defending parties have ample opportunity to meet the newly-

[1] Utah R. Civ. P. 15(a) (emphasis added).
[2] Pett v. Autoliv ASP, Inc., 2005 UT 2, ¶ 6, 106 P.3d 705, 706-07 (internal quotations and citation omitted).

raised matter.[3] The Supreme Court has approved of allowing amendments to pleadings as little as four weeks before a scheduled trial.[4]

In this matter, the amendment comes more than seven months before the scheduled hearing on the merits set for late September 2007. The parties have not begun briefing any of the issues raised in the First Amended Request for Agency Action, and the administrative record for this matter has been available to the parties for little over a week. The request for leave to amend is therefore timely, and the DAQ and other parties will have ample time to respond to the newly-raised issue.

In addition to timeliness, Utah courts consider the justification for the delay and any prejudice to responding parties in deciding a motion for leave to amend.[5] In this matter, the administrative record was only made available to the parties last week, and the parties only obtained searchable electronic copies on February 15, 2007, and this motion is being filed the very next day. The administrative record was necessary to confirm the factual basis for the newly-raised issue, namely that there was no 18-month report provided to DAQ by the company as required in the AO, that the 18-month period had passed without commencement of construction, and that DAQ did not conduct a review of the AO after 18 months. The delay in amending the request for agency action is fully justified by the previous unavailability of the administrative record.[6]

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[3] Gillman v. Hansen, 26 Utah 2d 165, 486 P.2d 1045-46 (1971) (stating that the court should "allow amendments freely where justice requires, and especially is this true before trial"); Lewis v. Moultree, 627 P.2d 94, 98 (Utah 1981).
[4] Savage v. Utah Youth Village, 2004 UT 102, ¶¶ 9-10, 104 P.3d 1242, 1245-46.
[5] Savage, 2004 UT 102, ¶ 9.
[6] A party is fully justified in waiting to move to amend until reliable confirmation of the facts can be obtained. Kelly v. Hard Money Funding, Inc., 2004 UT App 44, ¶ 38, 87 P.3d 734. Furthermore, by moving to amend immediately after receiving the administrative record, Sierra Club is not acting out of "dilatory motive, bad faith, or

A motion for leave to amend a pleading should be granted unless there would be "undue or substantial" prejudice to the responding party.[7] The Utah Supreme Court has held that a motion to amend should be denied only where "the opposing side would be put to unavoidable prejudice by having an issue adjudicated for which he had not had time to prepare."[8] In this matter, because the proceedings have barely begun, there is no prejudice to the other parties – much less undue, substantial, or unavoidable prejudice.

Sierra Club respectfully submits that it is in the interest of justice to allow this amendment, and requests that the Board grant this motion. If the Board denies this motion, Sierra Club could file a separate request for agency action on this claim and move to consolidate proceedings on that separate request with this matter. Because the claim raised in Statement of Reasons # 22 in the Second Amended Request for Agency Action is based on the automatic expiration of the permit, and not to a particular action by the Division of Air Quality, there is no time limitation for Sierra Club to make such a filing. For the reasons stated above, and in the interest of administrative efficiency, we respectfully request that the Board grant Sierra Club leave to file its Second Amended Request for Agency Action in this matter.

Dated: February 16, 2007

___/s/_____
JORO WALKER
DAVID BECKER
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unreasonable neglect" that would justify denying the motion for leave to amend. Swan Creek Village Homeowners v. Warne, 2006 UT 22, ¶ 24, 134 P.3d 1122, 1127.

[7] Swan Creek, 2006 UT 22, ¶ 21.

[8] Kasco Servs. Corp. v. Benson, 831 P.2d 86, 92 (Utah 1992) (internal quotations and citation omitted).

CERTIFICATE OF SERVICE

I hereby certify that on this 16th day of February 2007, I caused a copy of the foregoing Memorandum in Support of Motion for Leave to Amend Request for Agency Action to be emailed to the following:

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BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station, Millard County, Utah Project Code: N0327-010 DAQE-AN0327010-04	:	SECOND AMENDED REQUEST FOR AGENCY ACTION

SECOND AMENDED REQUEST FOR AGENCY ACTION

Pursuant to Utah Administrative Code R307-103-3(1) and Utah Code § 63-46b-3(3), the Utah Chapter of the Sierra Club (Sierra Club) hereby files its Second Amended Request for Agency Action with Richard W. Sprott, Executive Secretary of the Utah Air Quality Board. The Sierra Club seeks review of the October 15, 2004 decision by the Utah Division of Air Quality and the Executive Secretary (collectively "UDAQ" or "DAQ") to issue an Approval Order (AO) granting a Prevention of Significant Deterioration (PSD) permit to Intermountain Power Service Corporation (IPSC) to construct and operate an additional 950 megawatt (MW) coal-fired power plant Unit #3 at the Intermountain Power Plant in Millard County, Utah (DAQE-AN0327010-04)(Project Code: N0327-010). Pursuant to Utah Admin. Code R307-103-3(2), R307-103-6(2)(c), and R307-103-3, the Sierra Club relies on the Statement of Standing/Petition to Intervene previously submitted with its First Amended Request for Agency Action.

I. Permit Number and Date of Mailing

As mentioned above, Sierra Club is contesting the Approval Order signed by Richard W. Sprott, Executive Secretary of the Utah Air Quality Board, on October 15, 2004 to authorize the construction and operation of an additional 950 MW coal-fired power plant unit at the Intermountain Power Plant in Millard County, Utah (DAQE-AN0327010-04)(Project Code: N0327-010). According to UDAQ, the date of mailing of the AO is October 15, 2004.

On August 4, 2006, the Utah Associated Municipal Power Systems (UAMPS) made a request by letter to DAQ notifying the agency of UAMPS's intent change the technology for the proposed IPSC Unit 3 from a subcritical to supercritical pulverized coal fired boiler. On August 17, 2006, DAQ responded that if found "in accordance with Condition 7 of the Approval Order number DAQE-AN0327010-04, a supercritical PC boiler is equivalent to the permitted unit," Letter from Rick Sprott to Doug Hunter, August 17, 2006, thereby approving the project changes. Sierra Club learned of the IPSC request on October 13, 2006 and of DAQ's decision to approve the IPSC request on October 17, 2006 when it received an emailed copy of the August 17, 2006 DAQ approval letter.

II. Statement of Legal Authority and Jurisdiction

Sierra Club brings this Request for Agency Action pursuant to Utah Admin. Code R307-103-3(1), which states that "[i]nitial orders and notices of violation, as described in R307-103-2(1)[1], may be contested by filing a written Request for Agency Action to the Executive Secretary, Air Quality Board, Division of Air Quality . . . ." Utah Code § 63-46b-3(3) specifies the content of this Request for Agency Action.

III. Statement of Facts and Reasons

A. Statement of Facts

On December 16, 2002 and May 14, 2003, IPSC submitted a Prevention of Significant Deterioration (PSD) permit application and its Notice of Intent (NOI) to add a 950 MW coal-fired unit to its existing Intermountain Power Plant, near Delta, Utah. The additional unit at Intermountain Power Plant (IPP Unit 3 or Unit 3) would result in a significant net emissions increase of carbon monoxide (CO), nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter with an aerodynamic diameter equal to or less than 10 micrometers (PM_{10}), volatile organic compounds (VOCs), lead, sulfuric acid mist (H_2SO_4), total reduced sulfur, and reduced sulfur compounds. Thus, the proposed coal-fired power plant unit is a "major modification" to the Intermountain Power Plant for those pollutants. The area in which the facility is to be located is currently designated as having attainment status for all pollutants. Therefore, the additional unit is required to meet the provisions of Utah's PSD regulation, Utah Admin. Code R307-405, in addition to other applicable provisions of the Utah Admin. Code, including the requirements of a Notice of Intent and Approval Order established by Utah Admin. Code R307-401.

IPP Unit 3 has the potential to emit at least 25 tons per year of hazardous air pollutants (HAPs). Therefore, the additional unit is considered to be a major source of

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[1] Utah Admin. Code R307-103-2(1) defines an initial order as, *inter alia*, "approval, denial, termination, modification, revocation, reissuance or renewal of permits, plans, or approval orders." Utah Admin. Code R307-103-2(1)(a). This Second Amended Request for Agency Action covers both the October 15, 2004 Approval Order and the August 17, 2006 Modification of the Approval Order.

HAPs and subject to Utah's provisions for case-by-case determination of maximum achievable control technology (MACT) limits for HAPs, pursuant to Utah Admin. Code R307-214-2.

Because the additional unit will be an electric utility steam generating unit capable of combusting more than 73 MW heat input of coal, the facility is subject to the New Source Performance Standards (NSPS) of 40 C.F.R. Part 60, Subpart Da, which Utah has incorporated by reference into state regulation at Utah Admin. Code R307-210-1.

The Sierra Club has been involved throughout the permitting process for the proposed IPP Unit 3. On April 14, 2003, the Sierra Club submitted extensive comments on the proposed project in advance of the public comment period, detailing the permitting requirements pertaining to the permit application. The Sierra Club participated in a UDAQ public hearing held in Delta, Utah on April 29, 2004. In addition, on May 20, 2004 and within the designated public comment period, the Sierra Club submitted extensive comments on the UDAQ Intent to Approve (ITA) the PSD permit for IPP Unit 3. Following the re-opening of the comment period, the Sierra Club supplemented its May 20, 2004 comments with additional comments submitted on June 30, 2004 and July 16, 2004.

On October 15, 2004, Richard W. Sprott, Executive Secretary of the Utah Air Quality Board, signed the AO authorizing construction and operation of the proposed 950 MW IPP Unit 3. According to the AO, the operation of the power plant would allow air emissions increases, in tons per year, of: 496.5 of PM_{10}; 2,775 of NO_x; 3,567.5 of SO_2; 5,946 of CO, and 107 of VOCs, and 199 of HAPs. With the AO, UDAQ released two memoranda titled "Response to Comments received on IPSC Intent to Approve number DAQE-IN327010-04," authored by Milka Radulovic, Environmental Engineer, and "Technical Analysis response to comments received on IPSC's Intent to Approve number DAQE-IN3227010-04," authored by Tom Orth, Air Quality Modeler.

On August 4, 2006, the Utah Associated Municipal Power Systems (UAMPS) made a request by letter to DAQ notifying the agency of UAMPS's intent change the technology for the proposed IPSC Unit 3 from a subcritical to supercritical pulverized coal fired boiler. On August 17, 2006, DAQ responded that if found "in accordance with Condition 7 of the Approval Order number DAQE-AN0327010-04, a supercritical PC boiler is equivalent to the permitted unit," Letter from Rick Sprott to Doug Hunter, August 17, 2006, thereby approving the project changes. Sierra Club learned of the IPSC request on October 13, 2006 and of DAQ's decision to approve the IPSC request on October 17, 2006 when it received an emailed copy of the August 17, 2006 DAQ approval letter.

DAQ issued its August 17, 2006 letter without first providing public notice and comment on the significant project changes proposed by IPSC to the Unit 3 facility. On November 13, 2006, Sierra Club mailed and emailed a formal request to Rick Sprott, Executive Director of DAQ responding to the project changes for the IPSC Unit 3 facility

and requesting that DAQ notify the public of those changes and designate a comment period for the public to respond to those changes. On November 15, 2006 Rick Sprott denied that request.

B. Statement of Reasons

As set forth below and in the Sierra Club's comments, UDAQ's approval of IPSC's PSD permit fails to comply with the Clean Air Act, the Utah Air Conservation Act, and the Utah Administrative Code. The Sierra Club hereby incorporate and reference their comments dated April 14, 2003, May 20, 2004, June 30, 2004, and July 16, 2004, and the documents submitted in support of those comments.

In addition, the Sierra Club sets forth the basis for its request for agency action below:

1. UDAQ Failed to Consider Adequately Integrated Gasification Combined Cycle (IGCC) in its BACT Determination and Failed to Require the Production Process for IPP Unit 3.

Integrated Gasification Combined Cycle (IGCC) is a method of producing electricity by gasifying coal, removing pollutants – including greenhouse gases – before combustion, and then burning the "clean" syngas in a modified combined cycle gas-fired power plant. IGCC is an available, demonstrated, clean coal combustion technology with significant emission reduction benefits.[2] As such, UDAQ is required to evaluate this technology comprehensively as part of its BACT analysis. The agency, however, claims otherwise.

To argue that it is not required to evaluate IGCC as part of BACT, UDAQ contends that "the scope of the BACT analysis is limited to control technologies that can be applied to the emission unit proposed by the applicant." Response to Comments at 7, #12. However, UDAQ's interpretation of the BACT analysis requirement is erroneous. Consideration of inherently lower emitting power production processes and techniques such as IGCC is required by Utah Admin. Code R307-101-2, the state regulation defining BACT. Legislative history, EPA guidance, the actions of regulators in other states, and other relevant considerations additionally confirm that because consideration of the process design is a necessary part of the BACT analysis, thorough evaluation of IGCC is mandated.

UDAQ also contends that while it was not required to consider IGCC in its BACT analysis, the evaluation was done. Response to Comments at 7, #12. This analysis – a

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[2] The Sierra Club has, in its May 20, 2004 comments on the ITA for the IPP project, detailed the basis for this and other statements regarding the need to evaluate IGCC as part of a proper BACT analysis for IPP. Because the organizations have already referenced and incorporated those comments into their Request for Agency Action, they will not repeat those detailed arguments here.

top-down review comparing the proposed pulverized coal-fired power plant to both circulating fluidized bed and IGCC plants of similar size – is legally and technically inadequate. *See* Appendix I-8 of the NOI. It contains fundamental flaws in both methodology and assumptions, as well as significant mathematical errors. These flaws result in a greatly overstated determination of the cost of IGCC and the amount of pollutants emitted by IGCC. These errors are compounded by an improper method of calculating incremental costs that, when taken together with the other errors, exaggerate the incremental costs of pollution removed by the IGCC plant by two orders of magnitude.

To the extent that UDAQ suggests that it has now revised its review of IGCC for the purposes of BACT, Response to Comments at 8, #14, this revision is inadequate for the purposes of state and federal law. For example, this review was not subject to public notice and comment. Moreover, because the Sierra Club has not had the opportunity to assess the revised analysis, they reserve the right to challenge its content. Because UDAQ states that this revised analysis determined IGCC is not appropriate for IPP Unit 3, the conclusions of the evaluation are incorrect.

Finally, as the Sierra Club makes clear in its May 20, 2004 Comments, the analysis required by law shows that IGCC **is** BACT for IPP Unit 3. This is because IGCC is an available technology, is technically feasible for the IPP project, and is the top ranked control technology. In addition, proper consideration of economic, environmental and energy impacts confirms that IGCC is BACT for IPP Unit 3.

In sum, UDAQ is required to consider IGCC exhaustively as part of its BACT analysis. The existing analysis, presented at Appendix I-8 of the NOI, is fatally flawed. The revised analysis errs in that it concludes IGCC is not appropriate for the IPP Unit 3. As a result, UDAQ has failed its statutory and regulatory duties to examine IGCC adequately and to require the Intermountain Power Service Company to utilize IGCC for its power plant expansion pursuant to a BACT determination. Until UDAQ takes these steps, the AO is illegal and should be rescinded and/or remanded to the agency for proper BACT analysis.

2. UDAQ Failed to Consider Adequately a Supercritical PC Boiler in its BACT Determination and Failed to Require Installation of this Technology for IPP Unit 3.

For essentially the same reasons provided above, UDAQ's consideration of supercritical PC boiler technology is legally inadequate and therefore the AO is fatally flawed. Supercritical boilers are up to 7% or more efficient than subcritical boilers. As a result, they use less fuel and emit less carbon dioxide. Further, such supercritical boilers achieve up to 17% lower emission rates of carbon monoxide (CO), nitrogen oxides (NOx) and sulfur oxides (SOx), as well as up to 15% lower PM emission rates.

Yet, UDAQ argues that it need not analyze this technology as part of its BACT determination. Response to Comments at 8, # 15. The agency's conclusion is flawed.

Consideration of inherently lower emitting power production processes and techniques such as supercritical boiler is required by Utah Admin. Code R307-101-2, the state regulation defining BACT. Legislative history, EPA guidance, the actions of regulators in other states, and other relevant considerations additionally confirm that because consideration of the process design is a necessary part of the BACT analysis, thorough evaluation of this technology is mandated.

To the extent that UDAQ suggests that it has now revised its review of supercritical boiler technology for the purposes of BACT analysis, Response to Comments at 8, #15, this revision is inadequate for the purposes of state and federal law. For example, this review was not subject to public notice and comment. Moreover, because the Sierra Club has not had the opportunity to assess the revised analysis, they reserve the right to challenge its content. Because UDAQ states that this revised analysis determined that a supercritical boiler is not appropriate for IPP Unit 3, the conclusions of the evaluation are incorrect.

Rather, evaluation of supercritical boilers is required, as this technology, although inferior to IGCC, is an available technology, is technically feasible for the IPP project, and is a better ranked control technology than that currently proposed for Unit 3. In sum, UDAQ is required to consider supercritical boiler technology exhaustively as part of its BACT analysis. The revised analysis errs in that it has not been subject to public comment and it concludes this technology is not appropriate for the IPP Unit 3. As a result, UDAQ has failed its statutory and regulatory duties to examine supercritical boiler technology adequately and to require the IPSC to utilize a supercritical boiler pursuant to a BACT determination. Until UDAQ takes these steps, the AO is illegal and should be rescinded and/or remanded to the agency for proper BACT analysis.

3. UDAQ Erroneously Failed to Address Carbon Dioxide and Other Greenhouse Gas Emissions.

In approving the construction and operation of IPP Unit 3, UDAQ did not address or set limits on carbon dioxide (CO_2) or other greenhouse gas emissions from the new unit. Typically, coal-fired boilers emit significant greenhouse gases. Yet, UDAQ declined to address greenhouse emissions, based on its belief that it has no legal or regulatory duty to limit or control these emissions. Response to Comments at 9, #16. UDAQ's understanding of Utah law is misguided.

Pursuant to the Clean Air Act and Utah Air Quality Act and their implementing rules, the State of Utah is obligated to regulate greenhouse gases. Further, pursuant to the definition of BACT, Utah Admin. Code R307-101-2, the agency is required to consider environmental impacts, such as greenhouse gas emissions, when determining BACT for a facility. Because UDAQ did not address, set limits on, or factor greenhouse emissions into its BACT analysis, the agency has failed its statutory and regulatory duties. Until UDAQ takes these steps, the AO is illegal and should be rescinded and/or remanded to the agency for proper consideration and regulation of these gases.

4. UDAQ Did Not Properly Set Sulfur Dioxide (SO_2) Emission Limits.

In authorizing IPP Unit 3, UDAQ did not properly set emission limits for sulfur dioxide. The final Unit 3 AO imposes SO_2 limits of 0.10 lb/MMBtu (24-hr block average) and 0.09 lb/MMBtu (30 day rolling average). The administrative record does not support these limits, and UDAQ's adoption of these limits lacks support in the administrative record.

For example, these emission limits and corresponding control efficiencies are not reflective of the maximum degree of emissions reduction that can be achieved by the proposed SO2 control equipment, as required by the Utah definition of BACT. Utah Admin. Code R307-101-2 & R307-401-6(1). As Intermountain Power Service Company states in their NOI, such controls can achieve 98% SO_2 reduction. At best, the 0.10 lb/MMBtu SO_2 limit would equate to a 92% reduction in SO_2 emissions. Thus, the emission levels are too low.

UDAQ further suggests that it is purposefully setting relaxed SO_2 emission limits so that the source can meet them on a continuous basis. Again, this reasoning is not supported by law or fact. First, the record confirms that Unit 3 will be able to meet appropriately more stringent standards routinely – the control equipment is designed to do just that. Second, UDAQ admits that the SO_2 control efficiency necessary to meet the Unit 3 emission standards is **lower** than the efficiency of existing well-controlled sources, such as IPP Units 1 and 2. Indeed, the two existing IPP units are meeting 94.5% removal efficiency with a lower sulfur-content coal than the worst case "design coal" for Unit 3. Third, UDAQ bases a Unit 3 emission limit on worst case sulfur content. This means that the source, which will likely be burning cleaner coal the majority of the time, **will** be able to meet stricter emission limits.

UDAQ must include SO_2 removal efficiency requirements in the AO. This is because the SO_2 BACT emission limits are based on worst case uncontrolled SO_2 emissions. An efficiency requirement would ensure proper operation and maintenance of the scrubber regardless of the sulfur content in the coal and even when lower sulfur content coal is burned. Control efficiency requirements are further warranted because operation of IPP Unit 3 will adversely impact visibility at nearby Class I areas, including Capitol Reef National Park, where SO_2 increment violations are occurring. As a result of these concerns, the removal efficiency requirement should reflect, at the very least, what the wet scrubber can achieve – at a minimum 94.5% SO_2 removal efficiency.

Thus, UDAQ's relaxed SO_2 BACT emission requirements are not grounded in law or fact and are too lenient. Similarly, the agency's decision not require both emission limits **and** removal efficiency requirements is erroneous. As a result, the AO is illegal and should be rescinded and/or remanded to the agency for proper consideration and regulation of SO_2.

5. UDAQ Failed to Require Coal Chemistry Data.

IPSC's permit application did not contain precise coal chemistry data due to the fact that the corporation had not identified the actual coal to be burned at IPP Unit 3. The failure to include coal chemistry data prevents an accurate determination of percent removal efficiency limits, short term emission rates, and total mass emissions of pollutants such as mercury. Moreover, the description of the coal type and coal quality in the permit application is often vague and conflicting. Thus, reliance on such information by UDAQ is arbitrary and capricious. In the event IPSC plans to blend coal, the final permit should contain a coal quality/coal blending requirement. UDAQ wrongfully deleted such a provision from an earlier draft of the permit.

In summary, the permit application was fatally flawed by failing to include coal quality and/or coal blending information. The application also contained internally inconsistent information on coal quality. UDAQ erroneously issued a final permit without adequate coal quality data. For these reasons, the AO is illegal and should be rescinded and/or remanded to the agency.

6. UDAQ Failed to Require Use of Continuous Opacity Monitoring Data to Ensure Compliance with the Visible Emissions BACT Limit.

In the AO, UDAQ required that visible emissions from all baghouses (including the Unit 3 main boiler stack) shall not exceed 10 percent opacity. AO, Condition 12. UDAQ specified that opacity observations shall be conducted according to 40 C.F.R. Part 60, Appendix A, Method 9, which is a manual method of measuring opacity requiring a certified opacity inspector to be present. No frequency for Method 9 observations is specified. Such unspecified monitoring is not sufficient to ensure continuous compliance with the opacity limit. This source will be equipped with a continuous opacity monitoring system (COMS), Condition 23 of the AO, and thus UDAQ must require the use this COMS to ensure continuous compliance with the visible emissions BACT limit as stated in 40 C.F.R. §§ 60.47a through 60.49a. Because UDAQ did not, the AO is illegal, and should be rescinded and/or remanded to the agency to ensure continuous compliance with the visible emission limit.

7. UDAQ Failed to Consider Sufficiently Activated Carbon Injection for Control of Mercury Emissions from IPP Unit 3 in its MACT Determination.

UDAQ did not perform an adequate analysis of the case-by-case mercury MACT. UDAQ did not require thorough consideration of activated carbon injection for control of mercury in its case-by-case MACT analysis. As sworn testimony and supporting documents relied on or provided at an April 20, 2004 hearing on the Roundup Facility before the Montana Board of Environmental Review establishes, activated carbon injection is an available technology for control of mercury emissions from coal-fired power plants.

UDAQ did not thoroughly evaluate activated carbon injection technology at IPP Unit 3 because "testing at [IPP] Unit 2 has shown high mercury removal efficiency using a baghouse and a wet scrubber." March 22, 2004 Modified Source Plan Review at 149. However, activated carbon injection is an add-on technology that would improve the mercury removal efficiency above what would be achieved with the wet scrubber and baghouse. This justification for failing to consider activated carbon in the MACT analysis is flawed. UDAQ erroneously failed to consider carbon injection in the mercury MACT analysis and the AO should be should be declared illegal, and should be rescinded and/or remanded to the agency for proper MACT analysis.

8. UDAQ Failed to Set MACT Emission Limits for Other Hazardous Air Pollutants to be Emitted by IPP Unit 3.

UDAQ did not set enforceable emission limitations for the other hazardous air pollutants (HAPs), aside from mercury, to be emitted by IPP Unit 3. Determination of MACT emission limits is required for all HAPs to be emitted by IPP Unit #3, pursuant to Utah Admin. Code R307-214-2, unless it is technically infeasible to enforce such an emission limit. UDAQ provided no justification that it was technically infeasible to impose and enforce emission limits for any of these HAPs. Indeed, other power plant permits include enforceable emission limits for several HAPs including the PSD permit for the Thoroughbred Generating Station in Kentucky, which included emission limits for beryllium, sulfuric acid mist, hydrogen fluoride and mercury emissions, and the PSD permit for the Roundup Power Project, which included emission limits for hydrogen fluoride, hydrogen chloride, mercury, arsenic, beryllium, cadmium, chromium and manganese. Thus, other permitting authorities have determined it **was** feasible to prescribe and enforce emission limits for these other HAPs.

Accordingly, UDAQ erred and failed to comply with state regulation by not including MACT emission limits for other HAPs to be emitted by IPP Unit 3. Consequently, the AO is illegal, and should be rescinded and/or remanded to the agency for proper MACT analysis.

9. UDAQ Did Not Properly Set NOx Emission Limits.

UDAQ requires the installation of ultra low NOx burners, overfire air and selective catalytic reduction (SCR) for NOx control, but sets the BACT emission limit for NOx at 0.07 lb/MMBtu based on a 30-day average. However, these emission limits do not reflect the maximum degree of emissions reduction that can be achieved by the proposed NOx control equipment, as required by Utah law. *See* Utah Admin. Code R307-101-2 & R307-401-6(1). This selection of controls can, and must be required to achieve a lower emission limit. UDAQ's suggestions that stricter limitations are not achievable or have not been required previously are unconvincing given the sound basis in the record and law for mandating tighter emission limitations.

For example, vendor literature shows that lower NOx emission rates can be achieved from the ultra low NOx burners. In addition, expected emission rates reported

in the NOI from the RACT/BACT/LAER Clearinghouse of overfire air and low NOx burners, reflect NOx emission rates of 0.15 lb/MMBtu to 0.33 lb/MMBtu, all lower than the projected 0.35 lb/MMBtu NOx emission rate from the planned NOx combustion controls at IPP Unit 3. *See also*, UDAQ's March 22, 2004 Modified Source Plan Review at 121. Further, the SCR should be able to achieve greater than 80% reduction in NOx emissions. Commercial SCR installations have shown that 90% NOx reductions can be achieved with low ammonia slip, and indeed, up to 95% NOx control can be achieved with SCR.

Further, the NO_x BACT limit of the AO is less stringent than NO_x BACT limits for other recently permitted coal-fired power plants. For example, the Roundup Power Plant in Montana was required as part of the BACT determination to meet a NO_x limit of 0.07 lb/MMBtu on a 24-hour average basis, which is more stringent than IPP Unit #3'S 30-day average NO_x BACT limit.

Thus, UDAQ's NO_x BACT emission limit is not grounded in law or supported by the administrative record. As a result, the AO is illegal and should be rescinded and/or remanded to the agency for proper consideration and regulation of NO_x.

10. UDAQ Failed to Require Sufficient Analysis of the Impacts of IPP Unit 3 on Soils and Vegetation.

Pursuant to Utah Admin. Code R307-405-6(2)(a)(i)(D), UDAQ must require a PSD permit applicant to provide a full and complete analysis of "the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification." *See also* 40 C.F.R. § 52.21(o)(1) & (2). In response to comments raised about the necessity for such an analysis, UDAQ responded "[t]here were no comments from the public that indicated that their crops were being damaged from the existing Units 1 and 2." Technical Analysis Memo at 4 (Comment 4). However, UDAQ's response fails to address the increased impacts associated with the addition of Unit 3.

Moreover, UDAQ did not evaluate the impacts of pollutants such as ozone, mercury, and CO_2, despite numerous scientific studies from Utah and elsewhere establishing that ozone pollution causes harm to native vegetation and crops. *See* May 20, 2004 Comments at 43 (citing scientific literature). UDAQ failed to sufficiently address the potential for impacts to these pollutants on soils and vegetation. *See* Technical Analysis Memo at 5-6 (Comment 6). Therefore, the relevant AO should be declared illegal, should be rescinded, and/or should be remanded to the agency for proper soils and vegetation.

11. UDAQ Must Analyze the Impacts of All Three IPP Units Together.

Pursuant to Utah Admin. Code R307-405-6(2) and R307-101-2, UDAQ is required to consider the cumulative effect of all sources on NAAQS, including the Utah

County nonattainment area, and PSD increments. UDAQ suggests that cumulative impacts need not be assessed "unless the impacts from the modified source alone or new source trigger cumulative modeling requirements (i.e. Class I and II SIL)." Technical Analysis Memo at 7 (Comment 12). However, UDAQ is erroneously interpreting the relevant regulatory provisions. Rather, UDAQ is required to include the new proposed Unit 3, as well as the existing Units 1 and 2, in all modeling assessments. Because it does not contain this analysis, the relevant AO is illegal and should be rescinded and/or remanded to the agency for assessment of the impacts of the IPP facility.

12. UDAQ Failed to Justify the Use of the Second Highest PM_{10} Monitored Value as Representative of Background Concentrations.

UDAQ failed to adequately justify the use of the second highest PM_{10} monitored value as representative of PM_{10} background concentrations. UDAQ attempts to justify the elimination of the highest 24-hour concentration by suggesting that "[t]he highest PM_{10} concentration monitored . . . occurred during a summertime high wind event, where windblown dust was the main contributor to the concentration." Technical Analysis Memo at 8 (Comment 14). UDAQ's decision lacked sufficient analysis to show that the true cause of the highest monitored PM_{10} value or to show that such occurrences are rare for the area. As a result, the AO for IPP Unit 3 should be declared illegal, should be rescinded, and/or should be remanded to the agency for **proper assessment of** compliance with the PM_{10} NAAQS requirements.

13. UDAQ Failed to Analyze Properly Impacts on the Utah County PM_{10} Nonattainment Area.

UDAQ failed to conduct adequate modeling analyses to determine whether IPP's impacts to the Utah County PM_{10} nonattainment area would trigger the requirement for emission offsets under Utah regulation. Pursuant to Utah Admin. Code R307-403-5(1)(a), to determine whether a source located outside a nonattainment area must obtain offsets, UDAQ must assess whether the maximum impact in the nonattainment area would be greater than 1µg/m^3 on a yearly basis or greater than 3 µg/m^3 on a 24-hour basis "for any combination of PM_{10}, sulfur dioxide, and nitrogen dioxide." In keeping with this requirement, UDAQ previously stated that "[u]ntil an acceptable model is available, the evaluation of impacts of sources outside a PM_{10} non-attainment area must add the maximum modeled primary PM_{10} to their maximum gaseous SO2 and gaseous NO_2 modeled results." August 7, 2003 Memo, attached to Sierra Club's May 20, 2004 Comments.

However, UDAQ failed to require an acceptable model that accords with Utah Admin. Code R307-403-5(1)(a). Rather, UDAQ states, IPSC "used the turbulence based dispersion option in Calpuff. This option was verbally approved by Kevin Golden before IP[SC] performed the modeling. EPA Region VIII did not have any concerns about the use of this method as part of their comments, so the UDAQ has approved the modeling." Technical Analysis Memo at 8 (Comment 15). Verbal approval from a meteorologist at EPA does not demonstrate compliance with Utah Admin. Rule R307-4.3-5(1)(a).

Therefore, the IPP Unit 3 AO should be declared illegal, should be rescinded, and/or should be remanded to the agency to ensure proper analysis of the impact to the Utah County PM_{10} nonattainment area.

14. The Proposed Facility Will Contribute to Class I SO_2 Increment Violations at Capitol Reef National Park.

UDAQ violated Utah regulations in issuing the AO because, as currently permitted, the IPP Unit 3 will contribute to violations of the Class I SO_2 increment (otherwise known as "maximum allowable increase") in Capitol Reef National Park. The National Park Service conducted a Class I SO_2 increment analysis that shows that **existing** sources in Utah are causing violations of the 3-hour average Class I SO2 increment in Capitol Reef National Park. The Park Service presented this analysis to UDAQ electronically before or in November of 2003. On March 25, 2004, the National Park Service submitted a letter to UDAQ that provided, among other things, the Park Service's formal findings that the three-hour average SO_2 increment was being violated by existing sources in Utah at Capitol Reef National Park.

IPP's modeling analysis showed that the proposed new unit would affect 3-hour average SO_2 concentrations at Capitol Reef National Park. Because the facility would contribute to the increment violations at Capitol Reef National Park (shown by the National Park Service's modeling analysis), UDAQ is prohibited from issuing the AO. *See* Utah Admin. Code R307-401-6(2), R307-405-6(2)(a)(i)(A) and R307-405-6(2)(c).

UDAQ's assessment of cumulative SO_2 increment consumption at Capitol Reef National Park and other Class I areas is flawed and cannot be relied on. Specifically, UDAQ improperly allowed the modeling of annual average SO_2 emissions rates from all contributing sources, aside from IPP Unit 3, rather than modeling the peak 3-hour average and 24-hour average SO2 emission rates from the contributing sources. UDAQ asserts that "[t]he UDAQ policy for determining short-term emission rates for PSD increment consumption is to use annual average emissions divided by hours of operation." Technical Analysis Memo at 2 (Comment 2). However, this approach is not consistent with the Guidelines on Air Quality Models, incorporated by reference into Utah regulations at Utah Admin. Code R307-410-2, and fails to protect sufficiently Class I airsheds including Capitol Reef National Park.

EPA provided written comments to UDAQ during the public comment period on the IPP Unit 3 ITA that reiterated this policy and stated that "[c]urrent EPA guidance. . . is to use the maximum actual emission rate for each averaging period for the most recent 2 years of operation." May 24, 2004 letter from Richard R. Long, Director, Air Program, EPA Region VIII, to Rick Sprott, Director, UDAQ at 5. EPA also stated that continuous emission monitoring (CEM) data may be used to determine actual short term average emission rates. As is shown by the National Park Service's modeling analysis, as well as by EPA's analysis of peak emissions compared to annual average emissions from contributing sources, UDAQ's approach greatly underestimated SO_2 emissions from contributing sources and thus greatly underestimated the amount of SO_2 increment being

consumed in Capitol Reef National Park and other areas. Not only is UDAQ's approach unlawful, but it also fails to reflect the emissions that actually affect 3-hour average SO_2 concentrations. Further, it is very likely that all of the power plants in the area could be operating at peak emission rates concurrently, especially during a summer heat wave. Yet, UDAQ ignored this likelihood and instead assumed each power plant would be concurrently emitting at much less than peak emission rates. Consequently, UDAQ's assessment is flawed and illegal and cannot be relied on to show no existing SO_2 increment violations at Capitol Reef National Park.

UDAQ's arguments against using CEM data are without merit. Technical Analysis Memo at 1. EPA has previously supported the use of CEM data, but has found pairing CEM data in space and time with meteorological data to be inappropriate for an increment analysis. *See* May 24, 2002 EPA Comments on North Dakota Department of Health's Proposed Determination Regarding the Adequacy of the SIP to Protect PSD Increments for Sulfur Dioxide. EPA has also stated that CEM data is the best data available for use in an increment analysis. *See* March 15, 2002 letter from EPA Region VIII to the North Dakota Department of Health. Both of these documents are available at http://www.epa.gov/region08/air/ndair.html.

Moreover, neither state or federal law supports the use of "significant impact levels" (SILs) to find that IPP Unit 3 would not contribute to the SO_2 increment violation at Capitol Reef National Park. Because IPP Unit 3 will increase SO_2 concentrations at Capitol Reef National Park, it will contribute to the increment violations. EPA policy states that, in an area with an existing increment violation, **any** impact is significant. *E.g., see* April 12, 2002 letter to Terry O'Clair, North Dakota Department of Health, from Richard R. Long, EPA Region VIII. In addition, EPA's longstanding interpretation of the statutory and regulatory provisions for the PSD increments clearly mandate that, in an area with existing PSD increment violations, the violations "must be entirely corrected before PSD sources which affect the area can be approved." 45 Fed.Reg. 52678 (August 7, 1980).

Thus, because the proposed facility will contribute to violations of the Class I SO_2 increment in Capitol Reef National Park, the relevant AO should be declared illegal, should be rescinded, and/or should be remanded to the agency for proper analysis of SO_2 increment violations and for compliance with emission offset requirements.

15. UDAQ Failed to Require a Complete Cumulative Class I Increment Analysis for IPP Unit 3.

Specifically, in its modeling, Intermountain Power Service Company failed to include any emissions from Unit 1 of the Hunter plant. According to PacifiCorp's NOI for its proposed Hunter Unit 4 plant, Units 1-3 were all permitted under the PSD regulations. Thus, all of the SO_2 emissions from these three units consume the available SO_2 increment. UDAQ's justification for not including Hunter Unit 1 does not comport with state or federal law. Specifically, UDAQ states "Pacificorp's Hunter Power Plant - Unit 1 was permitted under the

PSD regulations. However, the unit began operation in 1978 before the major source baseline date of August 17, 1979." Technical Analysis Memo at 12. However, the major source baseline date for SO_2 is defined in state law as January 1, 1975, not August of 1979. See Utah Admin Code R307-101-2 under "baseline date." According to Utah Admin. Code R307-405-5(2)(a), the actual emissions from any source which commenced construction after the major source baseline date consumes the increment. Since Hunter Unit 1 was permitted under the PSD regulations, then the unit must not have commenced construction before the SO2 major source baseline date of January 1, 1975, because the PSD regulations in effect at the time applied to sources commencing construction on or after June 1, 1975. (See 39 Fed.Reg. 42514, December 5, 1974). Thus, Hunter Unit 1 is clearly an increment-consuming source, and UDAQ's failure to include SO_2 emissions from Unit 1 of the Hunter power plant was erroneous and illegal.

Also, UDAQ failed to include emissions from the, now approved, Sevier Power Company plant in Sigurd, Utah or any short term SO_2 emissions increases expected from the proposed Unit 4 at the Hunter Power Plant. UDAQ also failed to include emissions from the approved Currant Creek natural gas power plant, and UDAQ failed to include SO_2 emissions from other proposed or approved energy projects. To be complete, Intermountain Power Service Company's Class I analysis must include all of these sources.

Therefore, the relevant AO should be declared illegal, should be rescinded, and/or should be remanded to the agency for proper and thorough Class I increment analysis.

16. UDAQ Failed to Address Adequately Significant Visibility Impact to Utah's Class I Areas.

UDAQ is required to consider and analyze visibility impacts to Class I areas. For example, according to Utah Admin. Rule R307-406-2(3), UDAQ must "insure that source emissions will be consistent with making reasonable progress toward the national visibility goal referred to in 40 CFR 51.3000(a)." Utah Admin. Code R307-406-2(3). UDAQ claims that this provision was enacted only to deal with plume blight. *See* Technical Analysis Memo at 13 (Comment 24). However, this is an erroneous interpretation of UDAQ's duties and fails to ensure progress towards visibility goals.

In fact, the National Park Service has indicated, "emissions from the existing IPP boilers could be diminishing visibility at the potentially affected Class I areas that we manage and adding the proposed new unit could further contribute to this visibility degradation." National Park Service, May 27, 2004, Comment Letter. Yet, contrary to its duties, UDAQ failed to consider the combined visibility impacts of the IPP facility. Therefore, the relevant AO should be declared illegal, should be rescinded, and/or should be remanded to the agency for proper Class I visibility analysis.

17. UDAQ Failed to Justify Sufficiently IPP Unit 3's Class II PM_{10} Increment Consumption.

In its April 1, 2004 ITA, UDAQ stated that "[t]he increment analysis indicated that the amount of PM_{10} 24-hour increment consumed by the proposed project would be greater than 50% of the standard; therefore, approval under Utah Administrative Code R307-401-6 (3) from the Utah Air Quality Board would be required." April 1, 2004 ITA at 2. However, the AO never went before the Utah Air Quality Board. Apparently, the company submitted a revised PM_{10} increment analysis on August 26, 2004, well after the close of the public comment period.

The public has not had the opportunity to review the revised PM_{10} increment analysis. Further it appears that in this revised analysis the IPSC has assumed lower emissions from fugitive dust sources associated with IPP Unit 3. Yet, the AO does not include enforceable emission limitations or measures for the lower PM_{10} emission rates used in IPSC's August 26, 2004 revised PM_{10} increment analysis. Without enforceable measures to ensure that fugitive dust emissions from IPP would stay at the reduced levels included in the revised PM_{10} modeling analysis, UDAQ violated state regulation by issuing the AO without obtaining Board approval. Utah Admin. Code R307-401-6(3). As a result, the relevant AO is illegal and should be rescinded and/or remanded to the agency either to obtain Board approval for the consumption of more than 50% of the Class II PM_{10} increment by Unit 3, or for the formulation and presentation to the public for comment, enforceable fugitive dust measures sufficient to show less than 50% PM_{10} increment consumption.

18. UDAQ Illegally Included an Affirmative Defense Provision for Excess Emissions Due to Startup, Shutdown and Scheduled Maintenance.

In Condition 24 of the AO, UDAQ illegally included an affirmative defense provision for excess emissions over any emission limit due to startup, shutdown, or scheduled maintenance. Inclusion of this provision in the AO conflicts with state and federal law. Further, UDAQ's decision to include such a provision in the AO is arbitrary and capricious given that the agency properly excluded it from the AO for the Sevier Power Company power plant issued by UDAQ just three days before the IPP Unit 3 AO.

Utah recently initiated rulemaking to adopt affirmative defense provisions as part of state regulation, but no rule has yet been adopted by the state. EPA provided comments to the state during the public comment period on the rule, which ended on November 1, 2004. EPA took issue with several aspects of Utah's proposed affirmative defense provisions and indicated that it would not be able to propose approval of the state rule as a revision to the SIP unless all of its concerns were addressed. October 22, 2004 letter from Richard R. Long, EPA Region VIII, to Rick Sprott, UDAQ at 2. Many of the problematic provisions identified by EPA also exist in the affirmative defense provision included in Condition 24 of IPP Unit 3 AO.

Thus, the affirmative defense provision in the AO is legally flawed and/or conflicts with state law and the federally approved SIP. Accordingly, the AO is illegal and should be rescinded and/or remanded to the agency to expunge the affirmative defense provision in Condition 24 of the AO.

19. UDAQ Failed to Allow the Public to Comment on Submittals Received After the Public Comment Period.

Pursuant to Utah Admin. Code R307-401-3:

> [w]ithin 90 days of receipt of a **complete application** including all the information described in R307- 401-2, the executive secretary shall either issue an order prohibiting the proposed construction, installation, modification, relocation or establishment if it is deemed that any part of it is inadequate to meet the applicable requirements of R307, or issue an order permitting the proposed construction, installation, modification, relocation, or establishment pursuant to the requirements of R307-401-5 and 6.[3]

Utah Admin. Code R307-401-3 (emphasis added)..

Following her or his review of a complete application, "the executive secretary shall advertise intent to approve or disapprove in a newspaper of general circulation in the locality of the proposed construction, installation, modification, relocation or establishment." Utah Admin. Code R307-401-4(1). Rather than complying with this procedure, UDAQ advertised its ITA IPSC's PSD permit prior to the receipt of a complete application.

According to UDAQ's Response to Comments, IPSC submitted a revised top-down BACT analysis that includes IGCC and supercritical boiler, *see* Response to Comments at 8 (Comment #14), and a revised PM_{10} modeling analysis on August 26, 2004, *see* Technical Analysis Memo at 9 (Comment #17), after the close of the public comment period. However, these submittals are crucial to the public's analysis of the proposed permit. For example, this August 26, 2004 revised PM_{10} modeling analysis appears to have determined that PM_{10} emissions would be reduced below the threshold requirements to avoid approval of the permit from the Utah Air Quality Board. This alteration of the PM_{10} analysis, as well as the revised top-down BACT analysis, are significant developments and the public should have been allowed to provide input. Accordingly, AO is illegal and should be rescinded and/or remanded to the agency to allow the public to participate in the permitting process based on access to the complete application.

[3] Utah Admin. Code R307-401-3 allows for more time to review the proposal if needed.

20. DAQ Violated Utah Law and Regulation by Failing to Provide Public Notice and Comment Relative to its August 17, 2006 Approval of Project Changes for Unit 3.

On August 17, 2006, DAQ approved a request by UAMPS and/or IPSC to change the technology for the proposed Unit 3 from a subcritical to supercritical pulverized coal fired boiler. DAQ approved the change without notifying the public or allowing comment. In doing so, DAQ failed to comply with Utah law and DAQ regulation.

Initially, the Unit 3 permit itself anticipates that the proposed project changes are subject to public notice and comment. Condition 4 of the Unit 3 permit specifically states: "Modifications to the equipment or processes approved by this AO that **could affect the emissions** covered by this AO **must** be reviewed and approved in accordance with R307-401-1."[4] October 15, 2004 Unit 3 Approval Order (DAQE-AN0327010-04) (emphasis added). Rule R307-401-1 in turn "establishes the application and permitting requirements for new installations and modifications to existing installations throughout the State of Utah . . . ." Utah Admin. Code R307-401-1. These requirements specifically provide for public notice and comment "prior to" a decision by the Executive Secretary to approve or disapprove the relevant application. Id. at R307-401-7.[5]

The proposed modification to the Unit 3 design can affect emissions from Unit 3. For example, information already in the record establishes, at a minimum, that installation of a supercritical boiler could for Unit 3 could achieve 17% lower emission rates of carbon monoxide, nitrogen oxides and sulfur oxides as well as up to 15% lower PM emission rates. I.e. Sierra Club May 20, 2004 Comments on Unit 3 Intent to

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[4] In his letter approving the Unit 3 technology change, the Executive Secretary stated that, under Condition 7, supercritical boiler technology was "equivalent" to the technology permitted by the Approval Order. August 17, 2006 letter from Executive Secretary to Doug Hunter. However, any equivalency finding does not supersede Condition 4, which requires public notice and comment relative to the modification of the Unit 3 design. This is because modifications can be equivalent. A proper reading of the AO would give meaning to both conditions and would require public notice and comment and a new AO for the technology change, even assuming, without conceding, equivalency.

[5] DAQ also regulations allow interested parties to file a request for agency action when the agency approves the modification of an AO. These regulations define an "initial order" to include a modification to an AO. Utah Admin. Code R307-103-2(1)(a). In turn, any initial order may be contested through a request for agency action. Id. R307-103-3(1). Thus, DAQ regulations acknowledge the significance of any modification of an AO by allowing it to be contested before the Air Quality Board. The same reasoning favors the opportunity for public notice and comment in conjunction with a modification of an AO, such as the Unit 3 design change.

Approve at 22 (citing PSD permit application for the Steag Power Desert Rock Energy facility, a supercritical pulverized coal facility comparable to the Unit 3 facility).[6]

In addition, DAQ regulations require public notice and comment on the Unit 3 design modification. Rule R307-401-8(4) allows the Executive Secretary to accommodate the "staged construction of a large source" by "issu[ing] an order authorizing" the proposal based on general plans. However,

> [s]ubsequent detailed plans will then be processed as prescribed in this paragraph. For staged construction projects the previous determination under R307-401-8(1) and (2) will be reviewed and modified as appropriate at the earliest reasonable time prior to commencement of construction of each independent phase of the proposed source or modification.

Utah Admin. Code R307-401-8(4). Rules R307-401-8(1) and (2) reference the process by which the Executive Secretary approves or disapproves a permit application. As stated above, a condition precedent to the issuance of such an order is that the public be notified of and given the opportunity to comment prior to any AO. Id. at R307-401-7.

IPSC's own characterization of the Unit 3 project changes implicates Rule R307-401-8(4). As the corporation states, it is "preparing bids for the engineering and procurement phase of construction" of Unit 3. August 4, 2006 Letter from Doug Hunter to Rick Sprott. Based on this explanation of the status of Unit 3, Rule R307-401-8(4) is triggered and DAQ must review the detailed plans relative to supercritical technology prior to the next "phase" of "construction."[7]

Finally, the proposed project changes cannot be considered "equivalent" to the proposal envisioned by the AO. As DAQ confirms, the AO is based on the IPSC's Notice of Intent (NOI) filed with DAQ and information provided through out the subsequent process. I.e. Unit 3 AO, Condition 6. The NOI itself plainly envisions installation of a subcritical boiler. Indeed, in reviewing the NOI and in response to public comment, DAQ declared that supercritical technology would "**not be appropriate**" for

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[6] At the time, DAQ took issue with the fact that the submission was only a permit application for the Desert Rock facility. See October 14, 2004 DAQ memo "Response to Comments received on IPSC Intent to Approve Number DAQE-IN327010-04" at 8-9. Had DAQ accepted public comment on IPSC's modification request as required by Utah law, the conservation groups would have submitted the proposed permit EPA issued in July 2006 for the Desert Rock facility, which proposes stricter emission limits for that supercritical plant – emissions limits that should even be more rigorous for Unit 3. Sierra Club hereby references and incorporates that the Desert Rock proposed permit and all supporting materials available at: http://www.epa.gov/region9/air/permit/desertrock/

[7] Conservation groups point out this requirement based on IPSC's characterization of its Unit 3 proposal. Conservation groups in no way concede that IPSC is in compliance with Condition 8 of the Unit 3 AO, and, indeed, request that the Executive Secretary withdraw the AO because it is, by its own terms, out of date.

the Unit 3 facility. October 14, 2004 DAQ memo "Response to Comments received on IPSC Intent to Approve Number DAQE-IN327010-04" at 8-9 (emphasis added). As a result, DAQ cannot now suggest that approval of a technology it once refused to considered for Unit 3 is equivalent to the proposed project as set forth in the NOI and AO.

Moreover, if, as IPSC suggests, the maximum heat input capacity of Unit 3 will remain constant, the generating capacity of the facility would increase because of the greater efficiency of the supercritical boiler.[8] As a result, the proposed design change cannot be considered "equivalent" to the prior design. In addition, a Unit 3 supercritical boiler should achieve significantly lower emission rates. Results such as these must be considered as part of any appropriate BACT analysis for the technology change, and be reflected in lower emission limits in the permit regardless of whether a supercritical boiler or IGCC is ultimately chosen as BACT. This again means that the subcritical and supercritical technologies cannot be deemed equivalent and a new AO process is necessary.

21. DAQ Violated Utah Law and Regulation by Approving the Project Design Changes Without Completing Required Modeling and Analyses and Without Changing Permit Terms and Conditions.

Initially, Sierra Club underscores the disadvantage it faces because there has not been any public notice and comment associated with the project design changes. By failing to elicit public comment on this proposed change, DAQ has kept the public in the dark about the details of the design modification. The public has not been able to question the IPSC data, has no knowledge of the source and basis for this information, and has not been able to request, through comment, clarification of the analysis or additional analysis. Moreover, Sierra Club has not had the time to fully analyze the proposed project changes and the extent to which they implicate Utah law and regulation. As a result, Sierra Club's causes of action relative to the project design changes are necessarily based on incomplete information. Sierra Club hereby reserves the right to amend this request for agency action based on information that comes to light as a virtue of this process.

Sierra Club hereby references and incorporates all causes of action listed above and reiterates that they still apply to DAQ's approval of the original project and to project changes and to the decision making that lead to these approvals. In addition, Sierra Club reiterates that, in considering the project changes, DAQ was required, as of August 2006, to:

- require and/or undertake thorough evaluation of the emission limitations achievable using other available methods, systems and techniques including

[8] This increase in generating capacity could range from a low estimate of 4% up to 10%, meaning an increase in generating capacity from 990 mega watts to 1,045 mega watts (gross).

integrated gasification combined cycle (IGCC) combustion technology as part of the BACT (best available control technology) analysis for the Unit 3 facility. In August 2006, the Department of Energy reported that there are some two dozen IGCC plants in various stages of development across the nation.[9] That same month, Xcel energy announced that it will build an IGCC facility in the interior West.[10] The significant changes proposed by IPSC require examination of emission limitations achievable at Unit 3 with available technology.

- require and/or undertake thorough evaluation of the emission limitations achievable using supercritical technology.
- reexamine appropriate emission limits and require lower emission limitations on carbon monoxide, nitrogen oxides, sulfur oxides and particulate matter, as well as carbon dioxide. For example, the criteria pollutant emission limitations EPA recently proposed for the Desert Rock Energy Facility, which will employ supercritical boilers, are appreciably lower than those DAQ has established for Unit 3.[11] In addition, IPSC's consultant, CH2M Hill, suggests that that lower emissions on an annual basis could be achieved. Response to Public Comments Received by UDAQ on the Daft Approval Order IPP Unit 3, August 2004 at 15.
- reinitiate all relevant processes and require or undertake all required analyses and/or modeling given that project changes modify the generating capacity of the unit. On this basis, DAQ should reconsider all permit terms and conditions.
- require new dispersion modeling based on any change in stack height. Although IPSC asserts stack parameters will not change, the corporation does not commit itself to holding stack height constant. The AO specifies a stack height of "at least" 712 feet and a stack height of 712 feet was modeled. But if stack height were to increase with the installation of the proposed supercritical boiler, dispersion modeling results would change.

22. The Approval Order for Unit 3 is Now Invalid Because Construction Did Not Commence Within 18 Months of the Approval Order, and the Approval Order Has Automatically Expired.

The Executive Secretary signed the Approval Order for Unit 3 on October 15, 2004. The Utah PSD regulations provide, under "Source Obligations," that "the provisions of 40 C.F.R. 52.21(r), effective March 3, 2003, are hereby incorporated by reference." R307-405-19(1). That federal regulation, in turn, provides that:

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[9] The EPA Report is found at http://www.netl.doe.gov/coal/refshelf/ncp.pdf, while a press release announcing the report is found at http://www.netl.doe.gov/publications/press/2006/06046-Coal-Fired_Power_Plants_Database.html

[10] Information on Xcel's announcement can be found at: http://www.westgov.org/wga/press/igcc8-16-06.htm and http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_15531_26314-28427-0_0_0-0,00.html

[11] The EPA proposed Desert Rock permit is available at http://www.epa.gov/region9/air/permit/desertrock/desert-rock-proposed-permit.pdf.

> Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified.
>
> 40 C.F.R. 52.21(r)(2).

The AO is also subject to this federal regulation, which has been in effect since at least 1975, by the terms of the AO itself. The AO expressly provides that "[t]his AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including R307." AO at 14.

Twenty-eight months have now passed since the Executive Secretary signed the AO for Unit 3. Upon information and belief, construction has not yet commenced, notwithstanding that there has been no stay of the AO since it was approved. The Administrative Record for this AO, which UDAQ compiled and made available to the parties for duplication on February 6, 2007, and obtained in electronic format by Sierra Club on February 15, 2007, shows that there has been no extension of the 18-month period for automatic invalidation of the AO granted to IPSC.

Because more than 18 months have passed since the AO was issued on October 15, 2004, and no extension has been granted, the AO is now invalid, having expired automatically on or about April 15, 2006. Accordingly, IPSC must submit a new NOI to DAQ and re-initiate the AO process for approval to construct Unit 3.

In addition, the terms of the AO itself provide that "[i]f construction and/or installation has not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11." AO at 5. R307-401-11, now renumbered as R307-401-18, provides that

> Approval orders issued by the executive secretary in accordance with the provisions of R307-401 shall be reviewed eighteen months after the date of issuance to determine the status of construction, installation, modification, relocation or establishment. If a continuous program of construction, installation, modification, relocation or establishment is not proceeding, the executive secretary may revoke the approval order.

The Administrative Record also reflects that IPSC did not notify the Executive Secretary of the status of the project as required under the terms of the permit, and that the Executive Secretary did not conduct the review required by regulation in April 2006.

This review was mandatory under the regulations. The lack of a review prevented the DAQ from assessing whether any changed circumstances warranted revocation of the AO after eighteen months in which construction had not begun. The absence of that review, coupled with the automatic expiration of the approval to construct under R307-405-19(1) and corresponding source obligations in the federal regulations, require that IPSC now submit a new NOI to DAQ to obtain approval to construct Unit 3.

III. Request For Relief

Based on the above, the Sierra Club respectfully requests that the Air Quality Board declare the AO and AO modification for the proposed expansion to the Intermountain Power Plant illegal and invalid, revoke the AO for the additional unit, and/or remand the AO to UDAQ with instructions that the agency comply with the law and undertake or require the proper analysis as part of the permit and permitting process.

Dated: February 16, 2007

___/s/_____
JORO WALKER
DAVID BECKER
Attorneys for Sierra Club

CERTIFICATE OF SERVICE

I hereby certify that on this 16th day of February 2007, I caused a copy of the foregoing Second Amended Request for Agency Action to be emailed to the following:

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Attorneys for Sevier Power Company

BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – the Sevier Power Company 270 MW Coal-Fired Power Plant, Sevier County Project Code: N2529-001 DAQE-AN2529001-04	**SEVIER POWER COMPANY'S OPPOSITION MEMORANDUM TO SIERRA CLUB'S MOTION FOR LEAVE TO AMEND REQUEST FOR AGENCY ACTION**

Sevier Power Company ("Sevier Power") hereby files this Opposition Memorandum to the Sierra Club's Motion for Leave to Amend Request for Agency Action. On February 16, 2007, the Sierra Club filed its Motion for Leave to Amend Request for Agency Action ("Motion"). Sevier Power opposes the Sierra Club's Motion and respectfully requests that the Utah Air Quality Board ("Board") deny the Motion for reasons set forth herein.

INTRODUCTION

The Sierra Club is asking the Board to allow it to amend its Request for Agency Action dated November 12, 2004 ("RFA"). The Sierra Club's RFA seeks to invalidate the Approval Order issued to Sevier Power on October 12, 2004 ("AO"). The Sierra Club is now

seeking to add a cause of action which would provide a completely new and different basis for invalidating Sevier Power's AO separate and apart from the original RFA. The Sierra Club's is now alleging that Sevier Power's AO is invalid because more than 18 months have passed since the AO was issued without Sevier Power beginning construction or receiving an extension from the Executive Secretary. The Sierra Club claims that this is a violation of state and federal regulations. The Board should deny the Sierra Club's Motion because:

1) The amendment would be futile because the Sierra Club's new cause of action would not survive a motion to dismiss, and

2) The Sierra Club's claim is untimely.

FACTS

1. October 12, 2004 – Sevier Power receives its AO from the Executive Secretary of the Board.

2. November 12, 2004 – Sierra Club files its RFA.

3. May 12, 2005 – Board issues Order denying Sierra Club standing.

4. May 17, 2005 - Sierra Club files appeal to the Utah Court of Appeals re: standing issue.

5. November 17, 2005 - Sevier Power letter requesting an extension of the 18 month period.

> The Sevier Power Company requests the Executive Secretary to hold in abeyance the running of the 18 month period for construction to start from the date that the first Request for Agency Action was filed (November 1, 2004) until the formal adjudication process, including any appeals, is concluded and the review process confirms that the Sevier Power Company has a valid Approval Order. Please advise if further action on the part of Sevier Power is necessary in order to obtain the abeyance period requested. (emphasis added) (See Exhibit A Attached hereto)

6. April 12, 2006 – 18 months after Sevier Power's AO was issued.

7. June 2006 – Federal regulation 40 C.F.R. Section 52.21(r)(2) becomes effective in Utah.

8. November 21, 2006 – The Utah Supreme Court issued its decision allowing the Sierra Club to intervene in the Sevier Power proceeding.

9. February 16, 2007 – Sierra Club files Motion.

ARGUMENT

A. Sierra Club's Motion Should Be Denied Because the Amendment Would Not Withstand a Motion to Dismiss

The Board should deny the Sierra Club's Motion as futile because the proposed amendment would not withstand a motion to dismiss.

> ... [l]eave to file an amended complaint should be denied when movant seeks to assert a new claim that is illegally insufficient or futile.

Andalex Resources, Inc. v. Myers, 871 P.2d 1041, 1046 (Utah Ct. App. 1994).

> ... a court may deny a motion to amend as futile if the proposed amendment would not withstand a motion to dismiss ....

Jensen v. IHC Hospitals, Inc., 82 P.3d 1076, 1102 (Utah 2003), *quoting* Acker v. Burlington N. and Santa Fe Ry., Co., 215 F.R.D. 645, 647 (D.Kan.2003).

The Sierra Club's Motion to amend its RFA to add a new cause of action would be futile because 1) Sierra Club's alleged legal and factual basis for the new cause of action is erroneous, and 2) the claim is untimely.

1. Sierra Club's New Cause of Action Applies the Wrong Regulation

In connection with the Sierra Club's Motion, it also filed a Motion for Summary Judgment on the same 18 month issue relating to Sevier Power's AO. The Sierra Club bases this argument on the faulty assumption that a new federal regulation, 40 C.F.R. § 52.2 1(r), applies to Sevier Power's AO. This regulation states that,

> [a]pproval to construct shall become invalid if construction is not commenced within 18 months of receipt of such approval ...

40 C.F.R. § 52.21(r)(2).

The Sierra Club's proposed amendment to its RFA alleges that "twenty eight months have passed since the Executive Secretary signed the Approval Order for the proposed plant," and that "the AO is now invalid, having expired automatically on or about April 12, 2006." See Sierra Club proposed First Amended Request for Agency Action at 9.

However, the Board did not incorporate this federal regulation into the Utah Air Rules (at R307-405-19(1)) until the March 2006 Board meeting, to become effective June 2006.[1] Because this federal regulation was not part of the Utah Air Rules at the time the Executive Secretary issued Sevier Power's AO, Sevier Power is not subject to that regulation.

The relevant Utah Regulation, Utah Air Rule R307-401-18, provides the Executive Secretary with broad discretion on whether to revoke the AO if construction has not commenced after 18 months.

> Approval orders issued by the Executive Secretary in accordance with the provisions of R307-401 will be reviewed 18 months after the date of issuance to determine the status of construction, installation, modification, relocation, or establishment. If a continuous plan of construction, installation, modification, relocation or establishment is not proceeding, the Executive Secretary <u>may</u> revoke the approval order.

Utah Admin. Code R307-401-18 (emphasis added)

2. <u>Sierra Club's Now Cause of Action is Wrong on the Facts</u>

The Executive Secretary has discretion on whether to revoke Sevier Power's AO in the language set forth in the AO.

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[1] See Exhibit B. This Exhibit contains the amendments proposed to the Utah Air Quality Board at the March 2006 Air Quality Board meeting that were ultimately adopted by the Board.

> If construction and/or installation has not been completed within the eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11.

Sevier Power's AO at Condition #9. (emphasis added)

Neither the applicable Utah regulation or the provisions of the AO mandate an automatic expiration of the AO. Therefore, there was no automatic expiration of Sevier Power's AO as the Sierra Club asserts.

On November 17, 2005, Sevier Power sent a letter explaining the current status of the Sevier Power project and stating that construction had not commenced due to the ongoing litigation regarding the validity of its AO stating:

> The Sevier Power Company requests the Executive Secretary hold in abeyance the running of the 18 month period for construction to start from the date that the first Request for Agency Action was filed (November 1, 2004) until the formal adjudication process, including any appeals, is concluded and the review process confirms that the Sevier Power Company has a valid Approval Order.

See Exhibit A, November 17, 2005 letter from Sevier Power. (emphasis added)

The Executive Secretary was aware of the AO's appeal process and of the Sevier Power facility's construction status. Based on this information and upon knowledge of the permit conditions in Sevier Power's AO, the Executive Secretary did not exercise his discretion to revoke the AO. The Sierra Club's claims that the Executive Secretary failed to comply with the regulation is without a legal or a factual basis.

Even if the Board were to permit Sierra Club to amend its RFA with the proposed new cause of action, that cause of action would not survive a motion to dismiss because it is based on

a law that did not apply when Sevier Power's AO was issued, and because the factual basis on which it is based is erroneous.

B. Sierra Club's Claim is Untimely

> A request for agency action made to contest an initial order or notice of violation shall, to be timely, be received for filing within 30 days of the issuance of the initial order or notice of violation.

Utah Admin. Code R307-103-3(3).

As discussed above, the law and facts do not support Sierra Club's claim that Sevier Power's AO has automatically expired. However, even if the Board accepted the Sierra Club's position, the Sierra Club has unreasonably delayed filing this claim with the Board.

The Sierra Club claims that its new cause of action is based on the "automatic expiration of the permit, and not to a particular action of the Executive Secretary". Sierra Club argues that its delay in acting on the alleged violation is justified because the organization claims that it was not on notice regarding this issue until it received the administrative record on February 15, 2007.

The administrative record regarding the issuance of Sevier Power's AO is based on the events leading up to the issuance of the AO on October 12, 2004. The administrative record after this day is not relevant to the claims of Sierra Club's initial RFA, and is therefore not included.

The Sierra Club could have filed a Government Records Access Management Act ("GRAMA") request in April 2006, particularly considering its familiarity with the rules and its past activity in this case.

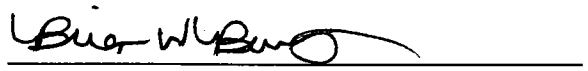
Even if one accepts the argument that the Sierra Club was waiting for the standing decision, the Utah Supreme Court issued its standing decision on November 21, 2006. The Sierra Club could have filed this Motion within 30 days from that date.

CONCLUSION

The Sierra Club's Motion for Leave to Amend Request for Agency Action should be denied for the reasons set forth above.

RESPECTFULLY SUBMITTED this 5th day of March, 2007.

FINLINSON & FINLINSON, PLLC
CALLISTER NEBEKER & McCULLOUGH



Fred W. Finlinson
Brian W. Burnett
Attorneys for Sevier Power Company

CERTIFICATE OF SERVICE

I hereby certify that on February 5th, 2007, the undersigned served a copy of the foregoing **SEVIER POWER COMPANY'S OPPOSITION MEMORANDUM TO SIERRA CLUB'S MOTION FOR LEAVE TO AMEND REQUEST FOR AGENCY ACTION** on the following by:

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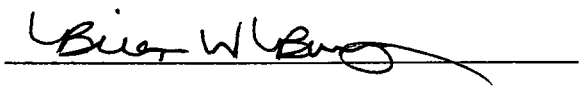

Exhibit A

RECEIVED
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AIR QUALITY

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November 17, 2005

John D. Jenks, Engineer
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Re: Approval Order: Sevier Power Company's 270 MW Coal-Fired Power Plant, Sevier County- CDS A; ATT: PSD: NSPS, MACT, HAPs, Title IV Major, Title V Major
Project Code: DAQE-AN2529001-04

Dear John Jenks:

Our firm represents the Sevier Power Company and they have asked me to give you an update on what has happened since the Approval Order (the "AO") referenced above was issued on October 12, 2004. In short, before the ink on the AO was dry, it was appealed. A battle over standing was fought by the Parties before the Utah Air Quality Board (the "Board"). The Board determined that the Sierra Club and the Grand Canyon Trust did not have standing. These parties have appealed the Board's ruling on standing to the Court of Appeals. The Court of Appeals has denied motions from the Sierra Club and Grand Canyon Trust to enlarge the record and to stay the Board's formal adjudication of the Sevier County Citizens For Clean Air and Clean Water's Request For Agency Action. These events have taken place over the following time line:

1. October 12, 2004, The Executive Secretary issued the above mentioned Approval Order for the Sevier Power Company.

2. November 1, 2004, the Sevier County Citizens For Clean Air and Water (the "Sevier County Citizens"), filed a combined Petition For Standing to Intervene and a Request For Agency Action on the issuance of the AO. This document was filed with the Board on November 4, 2004.

3. November 12, 2004, the Sierra Club and Grand Canyon Trust (collectively the "Sierra Club") filed a Request For Agency Action and a Statement of Standing and Petition to Intervene.

4. January 4, 2005, PacifiCorp also filed a Petition to Intervene and a Statement of Standing.

5. January 6, 2005, the Board issued a "Notification of Further Proceedings" which established a schedule for briefing and reply briefing with a hearing before the Board set for March, which was subsequently reset for hearing on April 13, 2005. The parties filed extensive briefs pursuant to this schedule.

6. April 13, 2005, the Board conducted a hearing on the standing of each of the petitioning parties. The Executive Secretary and the Sevier Power Company were granted standing by Board Rule as the main parties. The Citizens For Sevier County, the Sierra Club and Utah Power may only intervene if granted permission by the Board. After the matter was fully heard, the Board determined that it would grant standing to the Sevier County Citizens, and deny standing to both the Sierra Club and Utah Power. The Board also granted amicus status to both the Sierra Club and Utah Power. The Board mentioned that it would put its ruling in written form and approve the written draft as the final order at its next meeting in May.

7. May 12, 2005, the Board, after a review of its written order prepared by Counsel Fred Nelson, adopted the May 12, 2005 as its written order which both granted and denied standing to the respective parties as mentioned above.

8. May 17, 2005, the Sierra Club filed its Petition for Review with the Court of Appeals seeking a reversal of the May 12th Board decision denying standing. The Sierra Club also filed a Motion to Stay the Sevier County Citizens' Request For Agency Action pending its appeal to the Court of Appeals.

9. June 1, 2005, the Board held a hearing on the Sierra Club's Motion to Stay the Request For Agency Action. After the matter had been briefed and all parties had presented information to the Board, it determined that it would not stay the remaining Request For Agency Action filed by the Sevier County Citizens. This order was signed by the Chairman of the Board on June 6, 2005. A schedule for Request For Agency review was adopted which provided a time for answers to be filed, discovery, motions, and a proposed hearing in December, 2005 was also adopted by the Board.

   Since the Sierra Club filed its Petition For Review with the Court of Appeals, there are now two different tracts of appeal being pursued by the Sierra Club and the Sevier County Citizens. I will attempt to weave both appeals into one common time line.

10. June 10, 2005 (DAQ), the Executive Secretary and the Sevier Power Company filed with the Board their response to the Citizens November 1, 2004 Request For Agency Action.

11. June 23, 2005 (COA), the Board filed with the Appellate Court its revised record index identifying the record of the Agency in making its decision to deny standing.

12. June 24, 2005 (COA), the Sevier Power Company filed its Motion to Intervene in the Court of Appeals review of the Board's decision on standing. Intervention was granted by the Court of Appeals.

13. July 1, 2005 (COA), the Sierra Club filed a Motion For A Stay Pending Review, with supporting memorandum, requesting the Court of Appeals to stay the administrative proceedings in the DAQ.

14. July 18, 2005 (COA), the Executive Secretary filed a Motion to Intervene in the Sierra Club's Motion for the Stay. Its request for intervene was granted by the Court and the Executive Secretary filed briefs in opposition to the Sierra Club's Motion for a Stay and Motion to Expand the Record.

15. July 19, 2005 (COA), the Sierra Club filed a Motion to Supplement Record with Supporting Memorandum, and a Motion for Enlargement of Time to File Opening Brief.

16. July 28, 2005 (COA), a mediation conference was held at the Court of Appeals. All of the parties were present and participated in the conference. Subsequently, the Court Appointed Mediator issued an order releasing the parties from further participation in mediation.

17. August 29, 2005 (COA), the Court of Appeals, after reviewing the Parties' memorandums on the various motions submitted by the Sierra Club, issued its order denying the Sierra Club's Motion to Stay and also denying the Sierra Club's Motion to Supplement the Record.

18. August 30, 2005 (COA), the Court of Appeals issued a scheduling order requiring the Sierra Club's Brief to be filed by October 3, 2005. It was filed timely. The Executive Secretary and the Sevier Power Company filed their responsive briefs on November 2, 2005. The Sierra Club has an opportunity to file one more brief by December 2, 2005. After all of the briefs have been filed, the Court of Appeals will review the briefs and determine whether a hearing should be scheduled. They did not hold a hearing before denying the two previous motions of the Sierra Club. There could still be a hearing after the briefing is completed by December 2, 2005 and then after the hearing, the Court would then issue its decision on the Board's denial of standing to the Sierra Club. A final decision from the COA is still a number of months in the future.

19. September 23, 2005 (DAQ), the Executive Secretary served a set of interrogatories and request for the production of documents on the Sevier County Citizens.

20. October 3, 2005 (DAQ), the Executive Secretary filed a Motion to Compel because of the alleged failure of the Sevier County Citizens group to respond to the Interrogatories and

Requests For Production of Documents.

21. November 2, 2005 (DAQ), the Board held a hearing on the Executive Secretary's Motion to Compel. The Parties were present and submitted information to the Board about the lack of Discovery response from the Sevier County Citizens Group. After hearing from all parties, the Board granted the Motion to Compel and entered a written Order Regarding The Executive Secretary's Motion to Compel Discovery.

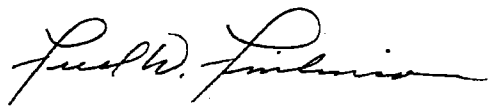
22. January 2006 (DAQ), this would be the earliest that a hearing on the Request For Agency Action could be held; however, at this meeting the Parties, including the Executive Secretary and the Sevier Power Company, may request the Board to rule on Preliminary Motions, and that the actual hearing, if necessary may more likely be scheduled for the February 2006 Board Meeting, with a written order being approved at the March 2006 Board Meeting. A decision made by the Board on the Request For Approval can be appealed by any party to the Court of Appeals. A Court of Appeal review of the final agency action, could take up to another year, once the appeal has been filed.

The uncertainty associated with the formal adjudicative process based on both Requests For Agency Action, coupled with the appeal of the decision denying standing to the Court of Appeals has required the Sevier Power Company to put on hold the construction of the power plant authorized by the October 12, 2004 Approval Order.

The Sevier Power Company requests the Executive Secretary to hold in abeyance the running of the 18 month period for construction to start from the date that the first Request For Agency Action was filed (November 1, 2004) until the formal adjudication process, including any appeals, is concluded and the review process confirms that the Sevier Power Company has a valid Approval Order. Please advise if further action on the part of Sevier Power Company is necessary in order to obtain the abeyance period requested. If you have any question, please call me at the number mentioned above.

Sincerely,

FINLINSON & FINLINSON, PLLC



Fred W. Finlinson

FWF
cc: The Sevier Power Company

12/19/05 contacted
Re: 18 month
Tech analysis

Exhibit B

R307. Environmental Quality, Air Quality.
R307-405. Permits: Prevention of Significant Deterioration of Air Quality (PSD).[

]

R307-405-1. Purpose.

This rule implements the federal Prevention of Significant Deterioration (PSD) permitting program for major sources and major modifications in attainment areas and maintenance areas as required by 40 CFR 51.166. This rule does not include the routine maintenance, repair and replacement provisions that were stayed by the DC Circuit Court of Appeals on December 23, 2003, pending appeal. This rule does not include the clean unit and pollution control project provisions that were vacated by the DC Circuit Court of Appeals on June 24, 2005. This rule supplements, but does not replace, the permitting requirements of R307-401.

R307-405-2. Applicability.

(1) Except as provided in (2), the provisions of 40 CFR 52.21(a)(2), effective March 3, 2003, are hereby incorporated by reference.

(2)(a) The provisions in 40 CFR 52.21(a)(2)(iv)(e) are not incorporated by reference.

(b) The last sentence in 40 CFR 52.21(a)(2)(iv)(f) is not incorporated by reference.

(c) The provisions in 40 CFR 52.21(a)(2)(vi) are not incorporated by reference.

(3) Notwithstanding the exemptions in R307-401, any source that is subject to R307-405 is subject to the requirement to obtain an approval order in R307-401-5 through 8.

R307-405-3. Definitions.

(1) Except as provided in (2)below, the definitions contained in 40 CFR 52.21(b), effective March 3, 2003, are hereby incorporated by reference.

(2) "Air Quality Related Values," as used in analyses under 40 CFR 52.21(p) that is incorporated by reference in R307-405-17, means those special attributes of a Class I area, assigned by a federal land manager, that are adversely affected by air quality.

(3)(a)(i) "Major Source Baseline Date" means:

(A) in the case of particulate matter:

(I) for Davis, Salt Lake, Utah and Weber Counties, the date that EPA approves the PM10 maintenance plan that was adopted by the Board on July 6, 2005;

(II) for all other areas of the State, January 6, 1975;

(B) in the case of sulfur dioxide:

(I) for Salt Lake County, the date that EPA approves the sulfur dioxide maintenance plan that was adopted by the Board on January 5, 2005;

(II) for all other areas of the State, January 6, 1975; and

(C) in the case of nitrogen dioxide, February 8, 1988.

(ii) "Minor Source Baseline Date" means the earliest date after the trigger date on which a major stationary source or a major modification subject to 40 CFR 52.21 or R307-405 submits a complete application under the relevant regulations. The trigger date is:

(A) In the case of particulate matter and sulfur dioxide, August 7, 1977, and

(B) in the case of nitrogen dioxide, February 8, 1988.

(iii) The baseline date is established for each pollutant for which increments or other equivalent measures have been established if:

(A) the area in which the proposed source or modification would construct is designated as attainment or unclassifiable under section 107(d)(i)(D) or (E) of the Act for the pollutant on the date of its complete application under 40 CFR 52.21 or R307-405; and

(B) in the case of a major stationary source, the pollutant would be emitted in significant amounts, or, in the case of a major modification, there would be a significant net emissions increase of the pollutant.

(iv) Any minor source baseline date established originally for the TSP increments shall remain in effect and shall apply for purposes of determining the amount of available PM10 increments, except that the executive secretary shall rescind a minor source baseline date where it can be shown, to the satisfaction of the executive secretary, that the emissions increase from the major stationary source, or net emissions increase from the major modification, responsible for triggering that date did not result in a significant amount of PM10 emissions.

(b) In the definition of "baseline area" in 40 CFR 52.21(b)(15)(ii)(b) insert the words "or R307-405" after "Is subject to 40 CFR 52.21".

(c) "Reviewing Authority" means the executive secretary.

(d)(i) The term "Administrator" shall be changed to "executive secretary" throughout R307-405, except as provided in (ii).

(ii) The term "Administrator" shall be changed to "EPA Administrator" in the following incorporated sections:

(A) 40 CFR 52.21(b)(17),

(B) 40 CFR 52.21(b)(37)(i),

(C) 40 CFR 52.21(b)(43),

(D) 40 CFR 52.21(b)(48)(ii)(c),

(E) 40 CFR 52.21(b)(50)(i),

(F) 40 CFR 52.21(l)(2),

(G) 40 CFR 52.21(p)(2), and

(H) [~~the first reference to Administrator in 40 CFR 52.21(y)(4)(i),~~

~~(I) the second reference to Administrator in 40 CFR 52.21(y)(7), and~~

~~(J)~~]40 CFR 51.166(q)(2)(iv).

(e) The definition of "emissions unit" in 40 CFR 52.21(b)(7), effective January 6, 2004, is hereby incorporated by reference.

(f) The definition of "replacement unit" in 40 CFR 52.21(b)(33), effective January 6, 2004, is hereby incorporated by reference.

(g) The following paragraphs that refer to clean units and pollution control projects are not incorporated by reference:

(i) 40 CFR 52.21(b)(2)(iii)(h),

(ii) 40 CFR 52.21(b)(3)(iii)(b),

(iii) 40 CFR 52.21(b)(3)(vi)(d),

(iv) 40 CFR 52.21(b)(32), and

(v) 40 CFR 52.21(b)(42).

([~~3~~]4) "Heat input" means heat input as defined in 40 CFR 52.01(g).

([~~4~~]5) "Title V permit" means any permit or group of permits covering a Part 70 source that is issued, renewed, amended, or revised pursuant to R307-415.

([~~5~~]6) "Title V Operating Permit Program" means R307-415.

([~~6~~]7) The definition of "Good Engineering Practice (GEP) Stack Height" as defined in R307-410 shall apply in this rule.

([~~7~~]8) The definition of "Dispersion Technique" as defined in R307-410 shall apply in this rule.

R307-405-4. Area Designations.

(1) Pursuant to section 162(a) of the federal Clean Air Act, the following areas are designated as mandatory Class I areas:

(a) Arches National Park,

(b) Bryce Canyon National Park,

(c) Canyonlands National Park,

(d) Capitol Reef National Park, and

(e) Zion National Park.

(2) Pursuant to section 162(b) of the federal Clean Air Act, all other areas in Utah are designated as Class II unless designated as nonattainment areas.

(3) No areas in Utah are designated as Class III.

R307-405-5. Area Redesignation.

Any person may petition the Board to change the classification of an area designated under R307-405-4, except for mandatory Class I areas designated under R307-405-4(1).

(1) The petition shall contain a discussion of the reasons for the proposed redesignation, including a satisfactory description and analysis of the health, environmental, economic and social and energy effects of the proposed re[~~s~~]designation.

(2) The petition shall contain a demonstration that the proposed redesignation meets the criteria outlined in Section VIII of the State Implementation Plan and 40 CFR 51.166(e) and (g).

R307-405-6. Ambient Air Increments.

The provisions of 40 CFR 52.21(c), effective March 3, 2003, are hereby incorporated by reference.

R307-405-7. Ambient Air Ceilings.

The provisions of 40 CFR 52.21(d), effective March 3, 2003, are hereby incorporated by reference.

R307-405-8. Exclusions from Increment Consumption.

(1) The following concentrations shall be excluded in determining compliance with a maximum allowable increase:

(a) concentrations attributable to the increase in emissions from stationary sources which have converted from the use of petroleum products, natural gas, or both by reason of an order in effect under section 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) over the emissions from such sources before the effective date of such an order;

(b) concentrations attributable to the increase in emissions from sources which have converted from using natural gas by reason of a natural gas curtailment plan in effect pursuant to the Federal Power Act over the emissions from such sources before the effective date of such plan;

(c) concentrations of particulate matter attributable to the increase in emissions from construction or other temporary emission-related activities of new or modified sources;

(d) the increase in concentrations attributable to new sources outside the United States over the concentrations attributable to existing sources which are included in the baseline concentration; and

(e) concentrations attributable to the temporary increase in emissions of sulfur dioxide, particulate matter, or nitrogen dioxides from stationary sources which are affected by plan revisions approved by the EPA Administrator as meeting the criteria specified in 40 CFR 51.166(f)(4). The temporary increase shall not exceed 2 years in duration unless a longer time is approved by the EPA Administrator. This exclusion is not renewable.

(2) No exclusion of concentration under (1)(a) or (b) above shall apply more than five years after the effective date of the order to which paragraph (1)(a) refers or the plan to which paragraph (1)(b) refers, whichever is applicable. If both such order and plan are applicable, no such exclusion shall apply more than five years after the later of such effective dates.

(3) No exclusion under (1)(e) shall apply to an emission increase from a stationary source which would:

(a) impact a Class I area or an area where an applicable increment is known to be violated; or

(b) cause or contribute to a violation of the national ambient air quality standards.

R307-405-9. Stack Heights.

The provisions of 40 CFR 52.21(h), effective March 3, 2003, are hereby incorporated by reference.

R307-405-10. Exemptions.

(1) The provisions of 40 CFR 52.21(i)(1)(vi) through (viii), effective March 3, 2003, are hereby incorporated by reference.

(2) The provisions of 40 CFR 52.21(i)(2) through (5), effective March 3, 2003, are hereby incorporated by reference.

R307-405-11 Control Technology Review.

The provisions of 40 CFR 52.21(j), effective March 3, 2003, are hereby incorporated by reference.

R307-405-12. Source Impact Analysis.

The provisions of 40 CFR 52.21(k), effective March 3, 2003, are hereby incorporated by reference.

R307-405-13. Air Quality Models.

The provisions of 40 CFR 52.21(l), effective March 3, 2003, are hereby incorporated by reference.

R307-405-14. Air Quality Analysis.

(1) The provisions of 40 CFR 52.21(m)(1)(i) through (iv), (vi), and (viii), effective March 3, 2003, are hereby incorporated by reference.

(2) The provisions of 40 CFR 52.21(m)(2) and (3), effective March 3, 2003, are hereby incorporated by reference.

R307-405-15. Source Information.

The provisions of 40 CFR 52.21(n), effective March 3, 2003, are hereby incorporated by reference.

R307-405-16. Additional Impact Analysis.

The provisions of 40 CFR 52.21(o), effective March 3, 2003, are hereby incorporated by reference.

R307-405-17. Sources Impacting Federal Class I Areas: Additional Requirements.

(1) The provisions of 40 CFR 52.21(p), effective March 3, 2003, are hereby incorporated by reference.

(2) The executive secretary will transmit to the EPA Administrator a copy of each permit application relating to a major stationary source or major modification and provide notice to the EPA Administrator of every action related to the consideration of such permit.

R307-405-18. Public Participation.

(1) Except as provided in (2), the provisions of 40 CFR 51.166(q)(1) and (2), effective March 3, 2003, are hereby incorporated by reference.

(2) The phrase "within a specified time period" in 40 CFR 51.166(q)(1) shall be replaced with the phrase "within 30 days of receipt of the PSD permit application".

R307-405-19. Source Obligation.

(1) Except as provided in (2) below, the provisions of 40 CFR 52.21(r), effective March 3, 2003, are hereby incorporated by reference.

(2) [~~(a)~~] The parenthetical phrase in the first sentence in 40 CFR 52.21(r)(6) shall be changed to read "(other than projects at a source with a PAL)."[

~~(b) The reference to "70.4(b)(3)(viii) of this chapter" in 40 CFR 52.21(r)(7) shall be changed to "R307-415-7i".~~]

R307-405-20. Innovative Control Technology.

(1) Except as provided in (2), the provisions of 40 CFR 52.21(v), effective March 3, 2003, are hereby incorporated by reference.

(2)(a) The reference to "40 CFR 124.10" in 40 CFR 52.21(v)(1) shall be changed to "R307-405-18".

(b) 40 CFR 52.21(v)(2) shall be changed to read "The executive secretary shall, with the consent of the governors of other affected states, determine that the source or modification may employ a system of innovative control technology, if:".

R307-405-21. Actuals PALs.

(1) Except as provided in (3), the provisions of 40 CFR 52.21(aa)(1) through (5) and (7) through (15), effective March 3, 2003, are hereby incorporated by reference.

(2) The provisions of 40 CFR 52.21(aa)(6), effective January 6, 2004, are hereby incorporated by reference.

(3)(a) The reference to "51.165(a)(3)(ii) of this chapter" in 40 CFR 52.21(aa)(4)(ii) shall be changed to "R307-403".

(b) The reference to "51.165(a)(3)(ii) of this chapter" in 40 CFR 52.21(aa)(8)(ii)(2) shall be changed to "R307-403".

(c) The references to "70.6(a)(3)(iii)(B) of this chapter" in 40 CFR 52.21(aa)(14)(ii) shall be changed to "R307-415-6a(3)(c)(ii)".

(d) The date of "March 3, 2003" in 40 CFR 52.21(aa)(15)(i) and (ii) shall be changed to "the effective date of this rule".

R307-405-22. Banking of Emission Offset Credit in PSD Areas.

Banking of emission offset credits in PSD areas will be permitted. To preserve banked emission reductions the executive secretary must identify them in either the Utah SIP or an order. The executive secretary will provide a registry to identify the person, private entity, or government authority that has the right to use or allocate the banked emission reduction and to record any transfer of or lien on these rights.

KEY: air pollution, PSD, Class I area
2006
Notice of Continuation August 11, 2003
19-2-104

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Attorneys for Intermountain Power Service Corporation

BEFORE THE UTAH AIR QUALITY BOARD

In the Matter of: Unit 3, Intermountain Power Service Corporation, Millard County, Utah DAQE-AN0327010-04	**MEMORANDUM IN OPPOSITION TO SIERRA CLUB'S MOTION FOR LEAVE TO AMEND REQUEST FOR AGENCY ACTION**

Intermountain Power Service Corporation ("IPSC"), by and through its counsel, respectfully submits the following Memorandum in Opposition to Sierra Club's Motion for Leave to Amend its Request for Agency Action ("Motion to Amend"). IPSC requests that the Utah Air Quality Board ("Board") deny Sierra Club's Motion to Amend.

INTRODUCTION

In its Motion to Amend, Sierra Club incorrectly argues that it is entitled to present an additional claim in its attack upon the Approval Order, issued October 15, 2004, for construction of IPSC's Unit 3. Specifically, Sierra Club tardily and improperly seeks to add a claim that the Approval Order expired because, according to the Sierra Club, IPSC allegedly failed to commence construction or obtain an extension from the Executive Secretary within eighteen

months after issuance of the Approval Order. See Proposed Second Amended Request For Agency Action, Statement of Reasons #22.

Sierra Club is wrong. Prior to the end of the eighteen-month period following issuance of the Approval Order, IPSC timely complied with the terms of the Approval Order by providing the Executive Secretary notification of the status of the project, the Executive Secretary reviewed the notification, and the Executive Secretary issued written confirmation that the Approval Order continued in effect and would not again be subject to construction status review until April of 2008. Therefore, Sierra Club's Motion to Amend must be denied because the claim it seeks to add is factually incorrect, untimely, and legally without merit.[1]

STATEMENT OF FACTS

1. On October 15, 2004, the Utah Department of Air Quality ("UDAQ") issued Approval Order #DAQE-AN0327010-04 for the addition of a new electrical generating unit, designated as Unit 3, at the Intermountain Power Generating Station.

2. According to the terms of the Approval Order (Condition 8), and under the applicable regulation (Utah Admin. Code R307-401-18), IPSC had eighteen months after the Order's issuance to either commence construction of Unit 3 or provide UDAQ "an update on the status of construction or installation." After eighteen months, UDAQ had the discretion to

[1] Sierra Club should also withdraw its Summary Judgment papers which are based on the same incorrect information. Obviously, Sierra Club cannot maintain that there are no "undisputed issues of material fact" regarding this issue.

revoke the Approval Order if UDAQ was unsatisfied with the status of the project. Id. The eighteen-month period ran from October 15, 2004 to April 15, 2006.

3. On January 13, 2006, IPSC sent a letter to Richard Sprott, Executive Secretary of UDAQ, providing an update of the status of Unit 3's construction and requesting a twenty-four month extension of the time to commence construction (attached hereto as Exhibit A).

4. On January 27, 2006, Richard Sprott, on behalf of UDAQ, sent a letter and memorandum to IPSC stating that the Approval Order had been reviewed and that the requested extension of time was granted (attached hereto as Exhibit B).

5. Now, over ten months after the end of the initial eighteen month review period under the Approval Order, and notwithstanding the extension determination issued by the Executive Secretary, Sierra Club belatedly and incorrectly seeks to amend its Request to include a claim that IPSC's Approval Order expired.

ARGUMENT

The Board should use the standards of Rule 15 of the Utah Rules of Civil Procedure (governing the addition of new claims in civil litigation) to guide its analysis of Sierra Club's Motion to Amend. Rule 15 provides that leave to amend "shall be freely given when justice so requires." Utah R. Civ. Proc. 15(a) (emphasis added). Although leave to amend may be freely given in general, there are certain circumstances where justice does not require a court to grant

leave to amend, and a court (or in this case, the Board) is instead obligated to deny a party's request for leave to amend. Such circumstances exist when (1) a party seeks to add a claim that is legally insufficient or futile; or (2) a party has unjustifiably delayed in asserting its new claim. Because both of these circumstances exist in the present case, the Board is obligated to deny Sierra Club's request.

I. SIERRA CLUB'S MOTION MUST BE DENIED BECAUSE SIERRA CLUB SEEKS TO ADD A CLAIM THAT IS LEGALLY INSUFFICIENT AND FUTILE.

Sierra Club's proposed new claim is legally insufficient and futile because the factual grounds on which it rests are wholly incorrect. It is well established in Utah law that "a party may not amend a complaint to add a claim that is legally insufficient or futile." Smith v. Grand Canyon Expeditions Co., 84 P.3d 1154, 1162 (Utah 2003); see also Aurora Credit Serv., Inc. v. Liberty West Dev., Inc., 970 P.2d 1273, 1282 (Utah 1998); Wright v. University of Utah, 876 P.2d 380, 387 (Utah Ct. App. 1994) ("[A] party is not entitled to file an amended complaint when the new claim is legally insufficient or futile."); Andalex Res. v. Myers, 871 P.2d 1041, 1046 (Utah Ct. App. 1994) ("[L]eave to file an amended complaint should be denied when the moving party seeks to assert a new claim that is legally insufficient or futile."); Frank v. U.S. West, Inc., 3 F.3d 1357, 1365 (10th Cir. 1993).

Sierra Club incorrectly asserts that IPSC did not obtain an extension of the time to commence construction, that IPSC did not notify the Executive Secretary of the status of the project, and that the Executive Secretary did not review the status of the project. See, Sierra Club's Second Amended Request for Agency Action, pages 20-22. As conclusively

demonstrated by the foregoing Statement of Facts and the attached Exhibits, all requirements were fulfilled and Sierra Club's assertions are wholly incorrect and without merit.

On January 13, 2006, Reed T. Searle, General Manager of IPA, sent a letter to Richard Sprott, Executive Secretary of UDAQ (see Exhibit A) specifically providing UDAQ with an update of the status of Unit 3's construction, as required by Condition #8 of the Approval Order. Id. In addition, the letter requested a twenty-four month extension of the period within which to commence construction, and explained the grounds therefore. Id. This request was made within eighteen months of the Approval Order's issuance. Id.

On January 27, 2006, Richard Sprott, as Executive Secretary of UDAQ, sent a responsive letter to IPSC. See Exhibit B. The letter and accompanying memorandum confirmed that UDAQ reviewed IPSC's Approval Order and the status of Unit 3's construction within eighteen months. In addition, the letter confirms that UDAQ properly exercised its discretion and granted IPSC a twenty-four month extension of the time to commence construction. Id. The Approval Order has therefore not expired.

Thus, the facts of the case indisputably demonstrate that Sierra Club's new claim is unsupported and must fail. Because Sierra Club's new claim cannot succeed, it is legally insufficient, and amending a Request for Agency Action to add a claim that cannot succeed would be futile. Accordingly, the Board must deny Sierra Club's Motion to Amend.

II. SIERRA CLUB'S MOTION TO AMEND MUST BE DENIED BECAUSE SIERRA CLUB UNJUSTIFIABLY DELAYED IN BRINGING ITS NEW CLAIM.

Sierra Club's Motion to Amend must also be denied because it is untimely. It is well settled that "untimeliness alone is a sufficient reason to deny leave to amend, especially when the party filing the motion has no adequate explanation for the delay." Frank, 3 F.3d at1365-66; see also Pallotino v. Rio Ranch, 31 F.3d 1023, 1026 (10th Cir. 1994); Aurora Credit Serv., Inc., 970 P.2d at 1282; Atcitty v. Bd. of Educ., 967 P.2d 1261, 1264 (Utah Ct. App. 1998). In examining timeliness, courts look at whether "the party seeking amendment [knew] or should have known of the facts upon which the proposed amendment is based" at an earlier time. Frank, 3 F.3d at 1366.

In this case, Sierra Club claims that IPSC's Approval Order expired on April 15, 2006, which is eighteen months after the Order's issuance. Sierra Club, having participated in the public comment on the Approval Order and having contested the Approval Order after its issuance in October of 2004, was well aware of the terms and conditions of the Approval Order, including the provision in Condition 8 thereof requiring review of construction status at the eighteen-month period ending April 15, 2006. Any claim Sierra Club had regarding the eighteen-month review became ripe on April 16, 2006. Sierra Club should have known at that time of any claim it might have had related to the end of the eighteen-month period and the provisions of Condition 8. Sierra Club delayed, however, almost a full year in bringing a claim.

In an effort to avoid the consequences of its lack of diligence, Sierra Club argues that it did not have access to the administrative record until February 6, 2007, and therefore could not

have known of the need to assert the claim earlier. See Memorandum in Support of Motion for Leave to Amend Request for Agency Action, page 3. This argument is a red herring and cannot be considered a justifiable excuse. The issuance of the "preliminary" administrative record in this case is completely unrelated to Sierra Club's new claim.[2]

Sierra Club has been on constructive and actual notice of the eighteen month review provision in Condition 8 of the Approval Order since before the Approval Order was issued in October of 2006. Sierra Club easily could have obtained the relevant information via a GRAMA request, a phone call to UDAQ, or numerous other ways on or about April of 2006 when the eighteen-month period ended. Because Sierra Club failed to do so and delayed ten months in bringing its claim, its new claim is untimely and Sierra Club does not have adequate justification for the delay. Accordingly, Sierra Club's Motion to Amend should be denied.

Sierra Club also argues it could file a separate Request for Agency Action, which would not be untimely. Sierra Club is incorrect. Even if Sierra Club could submit a new Request for Agency Action on this issue, such Request also would be untimely because it was not filed within 30 days of the end of the 18 month period (or at least 30 days after the Supreme Court

---

[2] The Board should not allow Sierra Club to complain that the "preliminary" administrative record and its index did not include the documents attached to this Memorandum. The "preliminary" administrative record did not include the extension documents because, until Sierra Club raised this claim, those documents were not relevant. Moreover, the administrative record index is also marked "preliminary" for good reason. During the negotiations and Board hearings regarding the schedule in this case, all parties recognized that documents may need to be added to the administrative record. There is no problem with the "preliminary" administrative record, rather the problem is Sierra Club's failure to exercise diligence in investigating this claim. Sierra Club should have filed a GRAMA request, made a phone call to DAQ or issued discovery prior to making this factually baseless claim.

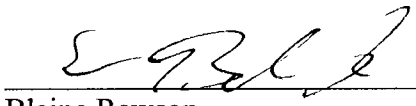
granted Sierra Club standing). See Utah Admin. Code R307-103-3. Therefore, Sierra Club's Motion to Amend is untimely and should be dismissed.

CONCLUSION

For the foregoing reasons, the Board should deny Sierra Club's Motion to Amend.

RESPECTFULLY SUBMITTED this 5th day of March, 2007.

HOLME ROBERTS & OWEN LLP



Blaine Rawson,
Holme Roberts & Owen LLP
Attorneys for Intermountain Power Service Corporation

#220621 v1

CERTIFICATE OF SERVICE

The undersigned hereby certifies that on this 5 day of March, 2007, a true and correct copy of the foregoing **MEMORANDUM IN OPPOSITION TO SIERRA CLUB'S MOTION FOR LEAVE TO AMEND REQUEST FOR AGENCY ACTION** was served as follows:

Joro Walker David H. Becker Western Resource Advocates 1473 South 1100 East, Suite F Salt Lake City, Utah 84105 jwalker@westernresources.org dbecker@westernresources.org	☐ ☐ ☐ ☐ ☒	U.S. Mail, postage prepaid Hand Delivery Fax (#) Overnight courier Electronically via Email
Rick Sprott, Executive Director Cheryl Heying, Acting Executive Director Division of Air Quality 150 North 1950 West Salt Lake City, Utah 84116 RSPROTT@utah.gov	☐ ☐ ☐ ☐ ☒	U.S. Mail, postage prepaid Hand Delivery Fax (#) Overnight courier Electronically via Email
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#220621 v1

EXHIBIT A

Intermountain Power Agency

January 13, 2006

Rick Sprott
Executive Secretary
Utah Division of Air Quality
150 North 1950 West
Salt Lake City, UT 84116

Re: IPA Unit 3 Request for 24 Month Extension

Dear Mr. Sprott:

The Intermountain Power Service Company ("IPSC") submits this request for a twenty-four (24) month extension of the period within which to commence construction under Approval Order #DAQE-AN0327010-04. The AO was issued by the Utah Department of Air Quality ("UDAQ") on October 15, 2004 for the addition of a new Unit 3 at the Intermountain Power Generating Station. The request will extend the time period to commence construction from April 15, 2006 until April 15, 2008.

Construction Status

General Condition #8 of the AO indicates that IPSC shall notify you in writing on the status of construction and/or installation of Unit 3 within 18 months of the issuance of the AO. The development participants have been actively engaged in many project development activities at great expense, including the following:

- developing joint ownership arrangements
- preparing agreements to govern the use of facilities in common with units 1 and 2
- preparing a joint operating agreement covering units 1, 2 and 3
- exploring fuel supply strategies
- initiating engineering and other technical work prerequisite to the procurement of equipment.

The development participants have spent in excess of $5 million dollars in preparatory work for the Unit 3 project and will continue to vigorously pursue these ongoing activities leading to the selection of an owner's engineer, preparation of

10653 South River Front Parkway, Suite 120, South Jordan, Utah 84095
(801) 938-1333 Fax (801) 938-1330

detailed specifications for construction, and procurement of necessary equipment and on-site construction activities commencing before April 15, 2008.

Extension Requests

Extension requests for major coal plants and other complex facilities are not uncommon. The Wyoming DEQ recently granted a 24 month extension to the Two Elks project and the North Dakota Department of Health granted a 36 month extension for a North Dakota PSD permit. Other states have granted extensions as well.

AO Timing

It is, quite literally, not possible to complete all of the tasks necessary to develop, design and construct a coal-fired power plant of this size in the 18 month window prescribed in the AO. For that reason, AO General Condition #8 and the underlying requirements contemplate a process to extend the AO as necessary.

In addition to the amount of time required to complete the development tasks noted above, there are long lead times for many construction-related activities and significant timing needs associated with the financial complexities surrounding a project with construction costs of over $1 Billion-a complicated 950 MW Unit 3 project with unique features, i.e. engineering designs, financing, and ownership. In addition, the legal challenge to AO and the subsequent appeal of the Air Board's decision has taken a tremendous amount of time and resources. Until that legal challenge is completed, the AO does not have the certainty necessary to make final construction plans and finalize financing.

Discussions among the development participants likewise require large amounts of time, along with the time to complete the resource planning requirements of individual development participants (including the SB 26 mandated PSC approval process for PacifiCorp). For all of these reasons, IPSC believes that adequate justification exists to extend the 18 month timeframe to commence construction for an added 24 months. The need is even greater because one of the original development participants unexpectedly withdrew from the project—the Los Angeles Department of Water & Power (LADWP). This in and of

itself caused significant delay and is an added reason why an extension is necessary.

BACT Update

IPSC and the development participants are mindful of the need to assure that there have not been any significant changes in Best Available Control Technology ("BACT") determinations since the AO for Unit 3 originally was issued. In that regard, a study by CH2MHill has gathered BACT determinations for facilities similar to the new Unit 3 at the Intermountain Power Generating Station, issued since October 15, 2004. See Attachment A for a list of the BACT determinations updated since October 15, 2004. This study reveals that no new pollution control technologies have been determined as BACT for facilities similar to Unit 3. Based on this review, IPSC has determined that no new technologies or emissions levels have been established as BACT that would require any revisions to the AO.

Accordingly, IPSC respectfully requests that a twenty-four (24) month extension be granted to allow IPSC sufficient time to further develop, design and begin construction on the new Unit 3. Thank you for your attention to this matter, and please contact me with any questions.

Sincerely,

Reed T. Searle

Reed T. Searle
General Manager

Enclosures
Cc: Doug Hunter, UAMPS
Ernie Wessman, PacifiCorp

Attachment A

The Approval Order for IPP Unit 3 was issued on October 15, 2004. Since that issuance, some new air quality construction permits have been issued for pulverized coal fired utility boilers. Enclosed is an updated listing of these permits similar to the one that was included in the appendix of the original Notice of Intent for IPP 3.

The permits that were issued subsequent to October 15, 2004 and were reviewed are Comanche Unit 3, Weston Unit 4, WYGEN Unit 2, Newmont Unit 1, as well as the re-issuance of the Bull Mountain Roundup Units 1 and 2 permit.

CH2M HILL has reviewed these permits and has determined that for NOx, all of these permits are in the range of 0.07 to 0.08 pounds per million BTU 30 day rolling average. The IPP AO is 0.07 pounds per million BTU 30 day rolling average. Therefore there is no justification to revise the IPP NOx limit.

For SO_2, all of these permits are in the range of 0.09 to 0.10 pounds per million BTU 30 day rolling average. The IPP AO is 0.09 pounds per million BTU 30 day rolling average and 0.10 24 hour average. Therefore there is no justification to revise the IPP SO2 limit.

For CO the permits range from 0.13 to 0.15 pounds per million BTU with the Comanche permit at 0.13 pounds per million BTU eight hour rolling average during normal operation but a much higher limit of 0.30 pounds per million BTU during startup. The Newmont permit is for a shorter averaging time (24 hour rolling average) while the IPP AO CO limit is for 30 day rolling average of 0.15 pounds per million BTU. The IPP AO is well in the range of the most recent permits and therefore we see no reason to revise the IPP CO limit.

For VOC, the permits range from 0.0027 to 0.01 pounds per million BTU. The Newmont permit is for 8.1 pounds per hour which is equivalent to 0.004 pounds per million BTU at full load. The IPP AO is 0.0027 pounds per million BTU which is the lowest BACT limit. Therefore we see no reason to revise the IPP VOC limit.

For PM_{10}, the permits range from 0.012 to 0.18 pounds PM_{10} filterable per million BTU. The IPP AO is at 0.012 pounds per million BTU for a three test run average. This is the lowest BACT limit of all the permits and therefore we see no reason to revise the IPP PM_{10} limit.

For H_2SO_4, the permits range from .001 to 0.005 pounds per million BTU. The IPP AO limits H_2SO_4 emissions to .0044 pounds per million BTU 24 hour block average. The Newmont limit is 0.001 pounds per million BTU (2.04 pounds per hour) using a dry lime FGD system while IPP Unit 3 will use a wet limestone scrubber. Given this difference in sulfur control technology the Newmont permit limit for H_2SO_4 is inapplicable. The remaining permits range from 0.0042 to .005 and the IPP is in this range. Therefore we see no reason to revise the IPP H_2SO_4 limit.

TABLE E-1
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for CO
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Proper Boiler Design and Opera	not given	0.15	lb/MMBTU		12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Combustion Control	not given	0.15	lb/MMBtu		7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Combustion Control	not given	0.13	lb/MMBtu	8-hour Rolling avg.	7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Good Combustion Controls	not given	0.15	lb/MMBTU	24-hour	5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Combustion Control	not given	0.15 3,399	lb/MMBTU tons/yr	1-Day 12-month Rolling avg.	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	Combustion Control	not given	0.15 3,000	lb/MMBTU lbs/hr	30-day Rolling avg. 8-hour Block avg.	10/15/2004

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:
- RBLC Determinations added during or after October 15, 2004
- SIC Code: 4911
- Process Type Code: 11.100 - Coal Combustion

TABLE E-2
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for VOC
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Proper Boiler Design and Operation	not given	0.003	lb/MMBtu		12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Combustion Control	not given	0.01	lb/MMBtu		7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Combustion Control	not given	0.0036	lb/MMBtu		7/5/2005
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Combustion Control	not given	0.0036 81.6	lb/MMBTU tons/yr	1-Day 12-month Rolling avg.	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr		not given	0.0027	lb/MMBTU	3 stack test run average	10/15/2004

Notes:

TABLE E-3
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for PM
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Fabric Filter	not given	0.012	lb/MMBTU	24-hour	5/05/2005 No. AP4911-1349

Notes:

TABLE E-4
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for PM_{10}
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Fabric Filter Baghouse	not given	0.012	lb/MMBTU		12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Fabric Filter	not given	0.012	lb/MMBtu		7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Fabric Filter	not given	0.012 0.020	lb/MMBtu	3-hour Rolling avg (filterable) 3-hour Rolling avg (filterable & condensable)	7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Fabric Filter	not given	0.012	lb/MMBTU	24-hour	5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Fabric Filter	not given	0.018	lb/MMBTU	3-hour Rolling avg.	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	Fabric Filer	not given	0.012 221	lb/MMBTU lbs/hr	3 stack test run avg. 24-hour Block avg	10/15/2004

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:

TABLE E-5
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for Lead
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit	Averaging Period	Permit Date and Permit No.

Notes:

TABLE E-6
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for Fluorides
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit	Averaging Period	Permit Date and Permit No.
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant	1	Coal Fired Boiler 2030 MMBTU/HR	Dry Spray Scrubber and Fabric Filter	not given	1.17 lbs/hr		5/05/2005 No. AP4911-1349

Notes:

TABLE E-7
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for SO_2
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Dry Flue Gas Desulfurization System	90%	0.15	lb/MMBtu	1-hour	12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Dry Lime FGD	not given	0.10 0.12	lb/MMBTU lb/MMBTU	30-day Rolling avg. 3-hour Block avg.	7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Dry Lime FGD	not given	0.1	lb/MMBtu	30-day Rolling	7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Lime Spray Dryer Scrubber	not given	0.09 0.065	lb/MMBTU lb/MMBTU	24-hour (Coal S >= 0.45%) - 95% removal eff, 30-day period 24-hour (Coal S <0.45%) - 91% removal eff, 30-day period	5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Dry Lime FGD	not given	0.10 0.09	lb/MMBTU lb/MMBTU	24-hour Block avg. 30-day Rolling avg.	10/18/2004
	Intermountain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	Wet Limstone FGD	not given	0.10 0.09	lb/MMBTU lb/MMBTU	24-hour Block avg. 30-day Rolling avg.	10/15/2004

Notes:

TABLE E-8
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for NO_x
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	SCR, Low NOx Burners, and Overfire Air	not given	0.1	lb/MBtu	1-hour	12/08/2005 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	SCR and Low NOx Burners	not given	0.07	lb/MBtu	30-day Rolling	7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	SCR and Low NOx Burners	not given	0.08	lb/MBtu	30-day Rolling	7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	SCR, Low NOx Burners, and Overfire Air	not given	0.067	lb/MBtu	24-hour rolling	5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	SCR and Low NOx Burners	not given	0.07	lb/MBtu	30-day Rolling	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	SCR and Low NOx Burners	not given	0.07	lb/MBtu	24-hour	10/15/2004

Notes:

TABLE E-9
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for H_2SO_4
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Dry Flue Gas Desulfurization System	not given	0.0064	lb/MMBTU		12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Dry Lime FGD	not given	No Limit			7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Dry Lime FGD	not given	0.0042	lb/MMBtu		7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Dry Spray Scrubber and Fabric Filter	not given	2.06	lbs/hr		5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Dry Lime FGD	not given	0.005	lb/MMBTU	24-hour	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	Wet Limestone FGD	not given	0.0044	lb/MMBTU	24-hour Block avg	10/15/2004

Notes:

TABLE E-10
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for Beryllium
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit	Averaging Period	Permit Date and Permit No.

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:
- RBLC Determinations added during or after January 1995
- SIC Code: 4911
- Process Type Code: 11.110 - Coal Combustion

The State
of Wyoming

Dave Freudenthal, Governor

Department of Environmental Quality

Herschler Building • 122 West 25th Street • Cheyenne, Wyoming 82002

ADMIN/OUTREACH	ABANDONED MINES	AIR QUALITY	INDUSTRIAL SITING	LAND QUALITY	SOLID & HAZ. WASTE	WATER QUALITY
(307) 777-7758	(307) 777-6145	(307) 777-7391	(307) 777-7368	(307) 777-7756	(307) 777-7752	(307) 777-7781
FAX 777-3610	FAX 777-6462	FAX 777-5616	FAX 777-6937	FAX 777-5864	FAX 777-5973	FAX 777-5973

May 17, 2004

Mr. Fred Carl
Director Environmental Services
Black Hills Corporation
P.O. Box 1400
Rapid City, SD 57709

Re: Air Quality Permit CT-3030 Extension

Dear Mr. Carl:

The Division is in receipt of your letter dated March 25, 2004, requesting to extend the construction period for Air Quality Permit CT-3030. Permit CT-3030, issued September 25, 2002, authorized the construction of a 500 megawatt (MW) pulverized coal fired electric generating facility, known as WYGEN 2, located at 13151 Hwy 51 approximately five (5) miles east of Gillette in Campbell County, Wyoming.

Condition 6 of the issued permit states that construction shall commence within 24 months of issuance of the permit. The allotted 24 months for construction is scheduled to lapse on September 25, 2004. An appeal of the final permit was filed on November 25, 2002 and action on the appeal is pending. For this reason, the Division will extend the permit for a period of one year. Construction must commence prior to September 25, 2005, for the approval to construct the WYGEN 2 Electric Generating Plant to remain valid.

If you should have any questions concerning this matter, please contact this office at (307) 777-7391.

Sincerely,

Dan Olson
Administrator
Air Quality Division

cc: Bob Gill
Mike Warren
Main File CT-3030

EXHIBIT B

State of Utah

Department of
Environmental Quality

Dianne R. Nielson, Ph.D.
Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

FILE COPY

DAQE-GN0327010-06

January 27, 2006

Reed Searle
Intermountain Power Agency
10653 South River Front Parkway, Suite 120
South Jordan, Utah 84095

Re: Review of the Approval Order DAQE-AN0327010-04 dated October 15, 2004.

Dear Mr. Searle:

The Utah Division of Air Quality (UDAQ) has received your letter dated January 13, 2006 in accordance with Approval Order number DAQE-AN0327010-04.

UDAQ reviewed your AO in accordance with the R307-401-11 of the Utah Administrative Code (UAC) and prepared the attached Memo.

Please note that Executive Secretary will not exercise the right to revoke the above referenced AO as outlined in R307-401-11. However, by April 15, of 2008, IPSC shall again notify the Executive Secretary in writing on the status of the construction and/or installation. At that time the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11, UAC.

Sincerely,

Richard W. Sprott, Executive Secretary
Utah Air Quality Board

RWS: MR:kw
Attachment: GN0327010A-06

State of Utah

Department of Environmental Quality

Dianne R. Nielson, Ph.D.
Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

FILE COPY

DAQE-GN0327010A-06

MEMORANDUM

TO: Intermountain Power Service Corporation (IPSC) Project Source File (Site ID 10327)

THROUGH: Richard W. Sprott, Executive Secretary
Regg Olsen, Permitting Branch Manager RDO 1/24/06
Rusty Ruby, NSR Section Manager, R 1/24/06

FROM: Milka Radulovic, NSR Engineer

SUBJECT: Review of the Approval Order (AO) for IPSC Unit #3 number DAQE-AN0327010-04 in Accordance with Condition 8 and Utah Administrative Code (UAC) Rule 307-401-11

DATE: January 23, 2006

We reviewed the IPSC letter dated January 13, 2006, sent to UDAQ in accordance with AO Condition 8. Reviewing the letter UDAQ finds that IPSC is engaged in many project development activities at substantial expense in excess of 5 million dollars.

UDAQ also finds that on November 12, 2004, IPSC petitioned the Utah Air Quality Board for review of Condition 24 in the AO dated October 15, 2004. Settlement negotiations took place between UDAQ and IPSC, resulting in a Joint Stipulation. The Joint Stipulation was approved by the Order of the Air Quality Board on September 7, 2005. The AO incorporates the terms of the Joint Stipulation. In addition, on November 15, 2004, Western Resources Advocates appealed the AO and action on the appeal is pending. These actions caused significant delay and necessitated an extension of the construction program.

For these reasons the Executive Secretary will not exercise the right to revoke the above referenced AO as outlined in R307-401-11. However, by April 15, of 2008, IPSC shall again notify the Executive Secretary in writing on the status of the construction and/or installation. At that time the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11, UAC.

PAUL M. McCONKIE (USB# 5881)
CHRISTIAN C. STEPHENS (USB #9068)
Assistant Attorneys General
MARK L. SHURTLEFF (USB #4666)
UTAH ATTORNEY GENERAL
160 East 300 South
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Attorneys for the Executive Secretary of the Utah Air Quality Board

BEFORE THE UTAH AIR QUALITY BOARD

In the Matter of: Sevier Power Company Power Plant Sevier County, Utah DAQE-AN2529001-04	EXECUTIVE SECRETARY'S MEMORANDUM IN OPPOSITION TO SIERRA CLUB'S MOTION FOR LEAVE TO AMEND REQUEST FOR AGENCY ACTION

The Executive Secretary of the Utah Air Quality Board ("Executive Secretary") hereby files this Memorandum in Opposition to Sierra Club's Motion for Leave to Amend its Request for Agency Action dated February 16, 2007. The Executive Secretary opposes the amendment because (1) Sierra Club's motion is untimely, and (2) the Executive Secretary complied with applicable law. Accordingly, the Executive Secretary respectfully requests that Sierra Club's motion be denied.

INTRODUCTION

Sierra Club seeks leave from the Utah Air Quality Board (the "Board") to amend its Request for Agency Action ("RFA") dated November 12, 2004. Sierra Club's RFA contests the Approval Order issued by the Executive Secretary to Sevier Power Company ("SPC") on October 12, 2004. Sierra Club now seeks leave to amend its RFA to add a cause of action which would provide an entirely new basis for invalidating the Approval Order, wholly distinct from the cause of action in the original RFA. Sierra Club's proposed amendment claims that according to state and federal regulation, the SPC Approval Order is now invalid because more

than 18 months (from the date of issuance of the AO) have passed without Sevier Power Company beginning construction on the project, and without an extension by the Executive Secretary.

This proposed amendment is completely distinct from all the other claims in the RFA, as the original RFA only addresses the Executive Secretary's decision to issue the approval order. As the Executive Secretary will demonstrate, the Board should deny Sierra Club's proposed amendment because the proposed amendment would be futile because Sierra Club's new cause of action would not survive a motion to dismiss.

ARGUMENT

A. Amendment Should not be Allowed Because It Would Not Withstand a Motion to Dismiss

It is well settled that "[l]eave to file an amended complaint should be denied when movant seeks to assert a new claim that is illegally insufficient or futile." Andalex Resources, Inc. v. Myers, 871 P.2d 1041, 1046 (Utah Ct. App. 1994). Moreover, "'. . . . a court may deny a motion to amend as futile if the proposed amendment would not withstand a motion to dismiss . . . . .'" Jensen v. IHC Hospitals, Inc., 82 P.3d 1076, 1102 (Utah 2003), *quoting* Acker v. Burlington N. and Santa Fe Ry., Co., 215 F.R.D. 645, 647 (D.Kan.2003).

Sierra Club's proposed new would be futile because 1) the claim is time-barred and 2) Sierra Club's alleged factual basis for the new cause of action is erroneous.

1. Sierra Club's Claim is Untimely

Sierra Club filed its RFA pursuant to Utah Admin. Code R307-103-3. Subsection (3) of that rule provides in pertinent part that "[a] request for agency action . . . shall, to be timely, be received for filing within 30 days of the issuance of the initial order or notice of violation." It is further well-settled that "[w]hen a cause of action set forth in an amended pleading is new, different, and distinct from that originally set up, there is not relation back [to the original

action], and the amendment is equivalent to the filing of a new action. Peterson v. Union Pac. R. Co., 8 P.2d 627, 630 (Utah 1932). Since Sierra Club's new claim would be introducing a "new, different, and distinct" cause of action, for timeliness purposes it needs to be treated as if it were a separate Request for Agency Action. Acknowledging the 30 day filing requirement under R307-103-3, Sierra Club asserts that it should be excused that this requirement does not apply because its new claim is based on an alleged "automatic expiration of the permit, and not to a particular action of the Executive Secretary," and that therefore, there is no time limitation for Sierra Club to make such a filing. *Id.* In its Motion for Summary Judgment, Sierra Club bases this argument on the faulty proposition that 40 C.F.R. § 52.21(r) applies to the Approval Order. That federal regulation states in pertinent part that "[a]pproval to construct shall become invalid if construction is not commenced within 18 months of receipt of such approval . . . ." 40 C.F.R. § 52.21(r)(2).

Sierra Club's proposed amendment alleges that "twenty eight months have passed since the Executive Secretary signed the Approval Order for the proposed plant," and that "the AO is now invalid, having expired automatically on or about April 12, 2006." *See* Sierra Club proposed First Amended Request for Agency Action at 9. This contention has no merit because the Board did not incorporate this federal regulation into the Utah Air Rules (at R307-405-19(1)) until the March 2006 Air Quality Board meeting, to become effective in June 2006.[1] Because this federal regulation was not part of the Utah Air Rules at the time the Executive Secretary issued the Approval Order, the Approval Order was not subject to the federal regulation.

Consequently, Sierra Club is left only with Utah Air Rule R307-401-18 and Condition No. 9 of the Approval Order, both of which endow the Executive Secretary with broad discretion to revoke the Approval Order if construction has not commenced after 18 months. Since neither

[1]See Exhibit A. This exhibit contains the amendments proposed to the Utah Air Quality Board at the March 2006 Air Quality Board meeting. It includes both the original rules and the proposed amendments that were ultimately adopted by the Board.

of these provisions mandate an automatic expiration of the approval order, there would be no automatic expiration of the Approval Order as Sierra Club asserts. Since Sierra Club cannot rely on an inapplicable federal regulation, its only avenue to contest an alleged violation of R307-401-18 is only through a new request for agency action, and thus, the 30 day filing requirement.

Sierra Club seeks to justify its delay in acting on the alleged violation by claiming that it was not on notice of the Executive Secretary's actions until it received the administrative record on February 15, 2007. This argument is wholly unpersuasive. The administrative record is only as broad as the allegations in Sierra Club's RFA, all of which deal with events leading up to the issuance of the Approval Order in October 2004. Anything post-dating that action is not relevant to the claims of Sierra Club's RFA, and thus is not properly part of the administrative record. Because there would be no reasonable expectation that the administrative record would contain any documentation concerning a post-permit 18 month review, Sierra Club's claim that it could not act without first having reviewed the administrative record is without justification.

Furthermore, nothing prevented Sierra Club from inquiring through a government records (GRAMA) request back in April 2006, particularly considering its familiarity with the rules and its past actions in this case. For example, in October 2004, Sierra Club filed a lengthy GRAMA request with the Division of Air Quality to obtain documents it believed relevant to its case. *See* Exhibit B, attached. Sierra Club's proactive past actions are inconsistent with its current assertion that it was powerless to determine the facts underlying its new cause of action until after it had received the administrative record. Further, even allowing Sierra Club the benefit of the doubt in April 2006 because its status as a party was on appeal, the Utah Supreme Court issued its standing decision on November 21, 2006, and Sierra Club did not file its motion to amend until February 16, 2007, some 87 days after it was granted standing. Under either timeline, Sierra Club's amendment is time-barred as a matter of law.

2. <u>The Executive Secretary Complied with the Applicable State Rule</u>

In addition to being untimely, Sierra Club's claim would not survive a motion to dismiss because there is no basis in law or fact. While the federal regulation providing for automatic expiration of the permit does not apply, there is no disagreement that Utah Admin. Code R307-401-18, does apply. That regulation states:

> Approval orders issued by the Executive Secretary in accordance with the provisions of R307-401 will be reviewed 18 months after the date of issuance to determine the status of construction, installation, modification, relocation, or establishment. If a continuous plan of construction, installation, modification, relocation or establishment is not proceeding, the Executive Secretary may revoke the approval order.

In its Motion for Summary Judgment, Sierra Club simply misstates the facts. As previously indicated, Sierra Club's motion is the result of Sierra Club's unjustifiable reliance on an administrative record which would not be expected to contain information on the 18 month review. A review of the relevant time period demonstrates that the Executive Secretary did in fact comply with R307-401-18. On November 17, 2005, Sevier Power sent a letter to the Executive Secretary explaining the current status of the SPC project. In that letter, Sevier Power stated that it had not commenced construction due to the ongoing litigation regarding its approval order. *See* Exhibit C, attached. This letter provided the Executive Secretary with the necessary knowledge of the "status of construction, installation, modification, relocation, or establishment" of the SPC facility. Utah Admin. Code R307-401-18. Based on this information and upon knowledge of the permit conditions in Sevier Power's Approval Order, the Executive Secretary used his discretion in not revoking the Approval Order. Therefore, Sierra Club's assertion that the Executive Secretary failed to comply with the regulation is without a factual basis.

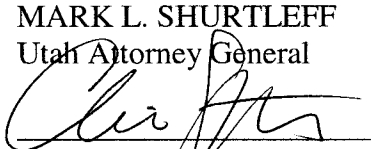
CONCLUSION

Based on the foregoing, the Executive Secretary opposes the amendment because the proposed amendment is without legal or factual basis and would not withstand a motion to

dismiss. Accordingly, the Executive Secretary respectfully requests that Sierra Club's Motion to amend its Request for Agency Action be denied

Dated this 5th day of March, 2007.

MARK L. SHURTLEFF
Utah Attorney General



PAUL M. McCONKIE
CHRISTIAN C. STEPHENS
Assistant Attorneys General

CERTIFICATE OF SERVICE

I hereby certify that on the 5th day of March, 2007, a true and correct copy of the foregoing Executive Secretary's Motion for Partial Judgment on the Pleadings was mailed, postage prepaid, and/or emailed to the following:

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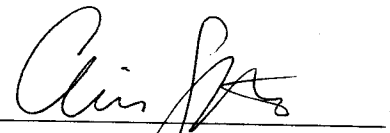

PAUL M. McCONKIE
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EXHIBIT A

State of Utah

Department of Environmental Quality

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Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

Air Quality Board
John M. Veranth, *Chair*
Ernest E. Wessman , *Vice-Chair*
Nan Bunker
Stead Burwell
Jerry D. Grover
James R. Horrocks
Scott Lawson
Dianne R. Nielson
Wayne M. Samuelson
JoAnn B. Seghini
Don Sorensen
Richard W. Sprott,
Executive Secretary

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

DAQ-007-06

UTAH AIR QUALITY BOARD MEETING

Working lunch session will be held prior
12:00-1:00 p.m.

168 North 1950 West (Bldg #2) Room 101

FINAL AGENDA

Wednesday, March 8, 2006
1:30 p.m.

168 North 1950 West (Bldg #2) Room 101

I. Call-to-Order.

II. Date of the Next Air Quality Board Meeting: April 5, 2006.

III. Approval of the Minutes for February's Board Meeting.

IV. Approve Location and Travel for Sevier Power Hearing. Presented By Rick Sprott.

V. Final Adoption: Repeal and Re-enact R307-405, Permits: Major Sources in Attainment or Unclassified Areas (PSD); Amend R307-110-9 and State Implementation Plan Section VIII, Prevention of Significant Deterioration. Presented by Colleen Delaney and Jim Schubach.

VI. Final Adoption: Repeal and Re-enact R307-401, Permits: New and Modified Sources. Presented by Colleen Delaney and Jim Schubach.

VII. Final Adoption: Amend R307-410, Permits: Emission Impact Analysis. Presented by Colleen Delaney and Jim Schubach.

VIII. Propose for Public Comment: Repeal R307-413, Permits: Exemptions and Special Provisions; Amend R307-101-2 Definitions; Amend R307-325, Davis and Salt Lake Counties and Ozone Nonattainment Areas: Ozone Provisions. Presented By Colleen Delaney and Jim Schubach.

IX. Informational Items
A. $PM_{2.5}$ Proposed Standards. Presented by Cheryl Heying.
B. Recent SIP Approvals. Presented By Jan Miller.
C. Compliance. Presented by Jeff Dean.
D. HAPS. Presented by Robert Ford.
E. Monitoring. Presented by Bob Dalley.

In compliance with the American with Disabilities Act, individuals with special needs (including auxiliary communicative aids and services) should contact Charlene Lamph, Office of Human Resources at (801) 536-4413 (TDD 536-4414).

R307. Environmental Quality, Air Quality.
R307-405. Permits: Prevention of Significant Deterioration of Air Quality (PSD).[

]

R307-405-1. Purpose.

This rule implements the federal Prevention of Significant Deterioration (PSD) permitting program for major sources and major modifications in attainment areas and maintenance areas as required by 40 CFR 51.166. This rule does not include the routine maintenance, repair and replacement provisions that were stayed by the DC Circuit Court of Appeals on December 23, 2003, pending appeal. This rule does not include the clean unit and pollution control project provisions that were vacated by the DC Circuit Court of Appeals on June 24, 2005. This rule supplements, but does not replace, the permitting requirements of R307-401.

R307-405-2. Applicability.

(1) Except as provided in (2), the provisions of 40 CFR 52.21(a)(2), effective March 3, 2003, are hereby incorporated by reference.

(2)(a) The provisions in 40 CFR 52.21(a)(2)(iv)(e) are not incorporated by reference.

(b) The last sentence in 40 CFR 52.21(a)(2)(iv)(f) is not incorporated by reference.

(c) The provisions in 40 CFR 52.21(a)(2)(vi) are not incorporated by reference.

(3) Notwithstanding the exemptions in R307-401, any source that is subject to R307-405 is subject to the requirement to obtain an approval order in R307-401-5 through 8.

R307-405-3. Definitions.

(1) Except as provided in (2)below, the definitions contained in 40 CFR 52.21(b), effective March 3, 2003, are hereby incorporated by reference.

(2) "Air Quality Related Values," as used in analyses under 40 CFR 52.21(p) that is incorporated by reference in R307-405-17, means those special attributes of a Class I area, assigned by a federal land manager, that are adversely affected by air quality.

(3)(a)(i) "Major Source Baseline Date" means:

(A) in the case of particulate matter:

(I) for Davis, Salt Lake, Utah and Weber Counties, the date that EPA approves the PM10 maintenance plan that was adopted by the Board on July 6, 2005;

(II) for all other areas of the State, January 6, 1975;

(B) in the case of sulfur dioxide:

(I) for Salt Lake County, the date that EPA approves the sulfur dioxide maintenance plan that was adopted by the Board on January 5, 2005;

(II) for all other areas of the State, January 6, 1975; and

(C) in the case of nitrogen dioxide, February 8, 1988.

(ii) "Minor Source Baseline Date" means the earliest date after the trigger date on which a major stationary source or a major modification subject to 40 CFR 52.21 or R307-405 submits a complete application under the relevant regulations. The trigger date is:

(A) In the case of particulate matter and sulfur dioxide, August 7, 1977, and

(B) in the case of nitrogen dioxide, February 8, 1988.

(iii) The baseline date is established for each pollutant for which increments or other equivalent measures have been established if:

(A) the area in which the proposed source or modification would construct is designated as attainment or unclassifiable under section 107(d)(i)(D) or (E) of the Act for the pollutant on the date of its complete application under 40 CFR 52.21 or R307-405; and

(B) in the case of a major stationary source, the pollutant would be emitted in significant amounts, or, in the case of a major modification, there would be a significant net emissions increase of the pollutant.

(iv) Any minor source baseline date established originally for the TSP increments shall remain in effect and shall apply for purposes of determining the amount of available PM10 increments, except that the executive secretary shall rescind a minor source baseline date where it can be shown, to the satisfaction of the executive secretary, that the emissions increase from the major stationary source, or net emissions increase from the major modification, responsible for triggering that date did not result in a significant amount of PM10 emissions.

(b) In the definition of "baseline area" in 40 CFR 52.21(b)(15)(ii)(b) insert the words "or R307-405" after "Is subject to 40 CFR 52.21".

(c) "Reviewing Authority" means the executive secretary.

(d)(i) The term "Administrator" shall be changed to "executive secretary" throughout R307-405, except as provided in (ii).

(ii) The term "Administrator" shall be changed to "EPA Administrator" in the following incorporated sections:

(A) 40 CFR 52.21(b)(17),

(B) 40 CFR 52.21(b)(37)(i),

(C) 40 CFR 52.21(b)(43),

(D) 40 CFR 52.21(b)(48)(ii)(c),

(E) 40 CFR 52.21(b)(50)(i),

(F) 40 CFR 52.21(l)(2),

(G) 40 CFR 52.21(p)(2), <u>and</u>

(H) [~~the first reference to Administrator in 40 CFR 52.21(y)(4)(i),~~

~~(I) the second reference to Administrator in 40 CFR 52.21(y)(7), and~~

~~(J)~~]40 CFR 51.166(q)(2)(iv).

(e) The definition of "emissions unit" in 40 CFR 52.21(b)(7), effective January 6, 2004, is hereby incorporated by reference.

(f) The definition of "replacement unit" in 40 CFR 52.21(b)(33), effective January 6, 2004, is hereby incorporated by reference.

(g) The following paragraphs that refer to clean units and pollution control projects are not incorporated by reference:

(i) 40 CFR 52.21(b)(2)(iii)(h),

(ii) 40 CFR 52.21(b)(3)(iii)(b),

(iii) 40 CFR 52.21(b)(3)(vi)(d),

(iv) 40 CFR 52.21(b)(32), and

(v) 40 CFR 52.21(b)(42).

([~~3~~]4) "Heat input" means heat input as defined in 40 CFR 52.01(g).

([~~4~~]5) "Title V permit" means any permit or group of permits covering a Part 70 source that is issued, renewed, amended, or revised pursuant to R307-415.

([~~5~~]6) "Title V Operating Permit Program" means R307-415.

([~~6~~]7) The definition of "Good Engineering Practice (GEP) Stack Height" as defined in R307-410 shall apply in this rule.

([~~7~~]8) The definition of "Dispersion Technique" as defined in R307-410 shall apply in this rule.

R307-405-4. Area Designations.

(1) Pursuant to section 162(a) of the federal Clean Air Act, the following areas are designated as mandatory Class I areas:

(a) Arches National Park,

(b) Bryce Canyon National Park,

(c) Canyonlands National Park,

(d) Capitol Reef National Park, and

(e) Zion National Park.

(2) Pursuant to section 162(b) of the federal Clean Air Act, all other areas in Utah are designated as Class II unless designated as nonattainment areas.

(3) No areas in Utah are designated as Class III.

R307-405-5. Area Redesignation.

Any person may petition the Board to change the classification of an area designated under R307-405-4, except for mandatory Class I areas designated under R307-405-4(1).

(1) The petition shall contain a discussion of the reasons for the proposed redesignation, including a satisfactory description and analysis of the health, environmental, economic and social and energy effects of the proposed re[~~s~~]designation.

(2) The petition shall contain a demonstration that the proposed redesignation meets the criteria outlined in Section VIII of the State Implementation Plan and 40 CFR 51.166(e) and (g).

R307-405-6. Ambient Air Increments.

The provisions of 40 CFR 52.21(c), effective March 3, 2003, are hereby incorporated by reference.

R307-405-7. Ambient Air Ceilings.

The provisions of 40 CFR 52.21(d), effective March 3, 2003, are hereby incorporated by reference.

R307-405-8. Exclusions from Increment Consumption.

(1) The following concentrations shall be excluded in determining compliance with a maximum allowable increase:

(a) concentrations attributable to the increase in emissions from stationary sources which have converted from the use of petroleum products, natural gas, or both by reason of an order in effect under section 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) over the emissions from such sources before the effective date of such an order;

(b) concentrations attributable to the increase in emissions from sources which have converted from using natural gas by reason of a natural gas curtailment plan in effect pursuant to the Federal Power Act over the emissions from such sources before the effective date of such plan;

(c) concentrations of particulate matter attributable to the increase in emissions from construction or other temporary emission-related activities of new or modified sources;

(d) the increase in concentrations attributable to new sources outside the United States over the concentrations attributable to existing sources which are included in the baseline concentration; and

(e) concentrations attributable to the temporary increase in emissions of sulfur dioxide, particulate matter, or nitrogen dioxides from stationary sources which are affected by plan revisions approved by the EPA Administrator as meeting the criteria specified in 40 CFR 51.166(f)(4). The temporary increase shall not exceed 2 years in duration unless a longer time is approved by the EPA Administrator. This exclusion is not renewable.

(2) No exclusion of concentration under (1)(a) or (b) above shall apply more than five years after the effective date of the order to which paragraph (1)(a) refers or the plan to which paragraph (1)(b) refers, whichever is applicable. If both such order and plan are applicable, no such exclusion shall apply more than five years after the later of such effective dates.

(3) No exclusion under (1)(e) shall apply to an emission increase from a stationary source which would:

(a) impact a Class I area or an area where an applicable increment is known to be violated; or

(b) cause or contribute to a violation of the national ambient air quality standards.

R307-405-9. Stack Heights.

The provisions of 40 CFR 52.21(h), effective March 3, 2003, are hereby incorporated by reference.

R307-405-10. Exemptions.

(1) The provisions of 40 CFR 52.21(i)(1)(vi) through (viii), effective March 3, 2003, are hereby incorporated by reference.

(2) The provisions of 40 CFR 52.21(i)(2) through (5), effective March 3, 2003, are hereby incorporated by reference.

R307-405-11 Control Technology Review.

The provisions of 40 CFR 52.21(j), effective March 3, 2003, are hereby incorporated by reference.

R307-405-12. Source Impact Analysis.

The provisions of 40 CFR 52.21(k), effective March 3, 2003, are hereby incorporated by reference.

R307-405-13. Air Quality Models.

The provisions of 40 CFR 52.21(l), effective March 3, 2003, are hereby incorporated by reference.

R307-405-14. Air Quality Analysis.

(1) The provisions of 40 CFR 52.21(m)(1)(i) through (iv), (vi), and (viii), effective March 3, 2003, are hereby incorporated by reference.

(2) The provisions of 40 CFR 52.21(m)(2) and (3), effective March 3, 2003, are hereby incorporated by reference.

R307-405-15. Source Information.

The provisions of 40 CFR 52.21(n), effective March 3, 2003, are hereby incorporated by reference.

R307-405-16. Additional Impact Analysis.

The provisions of 40 CFR 52.21(o), effective March 3, 2003, are hereby incorporated by reference.

R307-405-17. Sources Impacting Federal Class I Areas: Additional Requirements.

(1) The provisions of 40 CFR 52.21(p), effective March 3, 2003, are hereby incorporated by reference.

(2) The executive secretary will transmit to the EPA Administrator a copy of each permit application relating to a major stationary source or major modification and provide notice to the EPA Administrator of every action related to the consideration of such permit.

R307-405-18. Public Participation.

(1) Except as provided in (2), the provisions of 40 CFR 51.166(q)(1) and (2), effective March 3, 2003, are hereby incorporated by reference.

(2) The phrase "within a specified time period" in 40 CFR 51.166(q)(1) shall be replaced with the phrase "within 30 days of receipt of the PSD permit application".

R307-405-19. Source Obligation.

(1) Except as provided in (2) below, the provisions of 40 CFR 52.21(r), effective March 3, 2003, are hereby incorporated by reference.

(2)[~~(a)~~] The parenthetical phrase in the first sentence in 40 CFR 52.21(r)(6) shall be changed to read "(other than projects at a source with a PAL)."[

~~(b) The reference to "70.4(b)(3)(viii) of this chapter" in 40 CFR 52.21(r)(7) shall be changed to "R307-415-7i".~~]

R307-405-20. Innovative Control Technology.

(1) Except as provided in (2), the provisions of 40 CFR 52.21(v), effective March 3, 2003, are hereby incorporated by reference.

(2)(a) The reference to "40 CFR 124.10" in 40 CFR 52.21(v)(1) shall be changed to "R307-405-18".

(b) 40 CFR 52.21(v)(2) shall be changed to read "The executive secretary shall, with the consent of the governors of other affected states, determine that the source or modification may employ a system of innovative control technology, if:".

R307-405-21. Actuals PALs.

(1) Except as provided in (3), the provisions of 40 CFR 52.21(aa)(1) through (5) and (7) through (15), effective March 3, 2003, are hereby incorporated by reference.

(2) The provisions of 40 CFR 52.21(aa)(6), effective January 6, 2004, are hereby incorporated by reference.

(3)(a) The reference to "51.165(a)(3)(ii) of this chapter" in 40 CFR 52.21(aa)(4)(ii) shall be changed to "R307-403".

(b) The reference to "51.165(a)(3)(ii) of this chapter" in 40 CFR 52.21(aa)(8)(ii)(2) shall be changed to "R307-403".

(c) The references to "70.6(a)(3)(iii)(B) of this chapter" in 40 CFR 52.21(aa)(14)(ii) shall be changed to "R307-415-6a(3)(c)(ii)".

(d) The date of "March 3, 2003" in 40 CFR 52.21(aa)(15)(i) and (ii) shall be changed to "the effective date of this rule".

R307-405-22. Banking of Emission Offset Credit in PSD Areas.

Banking of emission offset credits in PSD areas will be permitted. To preserve banked emission reductions the executive secretary must identify them in either the Utah SIP or an order. The executive secretary will provide a registry to identify the person, private entity, or government authority that has the right to use or allocate the banked emission reduction and to record any transfer of or lien on these rights.

KEY: air pollution, PSD, Class I area
2006
Notice of Continuation August 11, 2003
19-2-104

R307. Environmental Quality, Air Quality.
R307-405. Permits: Prevention of Significant Deterioration of Air Quality (PSD).
R307-405-1. Definitions.

The following additional definitions apply to R307-405:

"Baseline Area" means any intrastate area (and every part thereof) designated as attainment or unclassifiable under Section 107(d)(1)(D) or (E) of the federal Clean Air Act in which the major source or major modification establishing the minor source baseline date would construct or would have an air quality impact equal to or greater than 1 ug/m3 (annual average) of the pollutant for which the minor source baseline date is established.

(1) Area redesignations under section 107(d)(1) (D) or (E) of the federal Clean Air Act cannot intersect or be smaller than the area of impact of any major stationary source or major modification which:

(a) Establishes a minor source baseline date; or

(b) Is subject to 40 CFR 52.21 or R307-405, and would be constructed in the same state as the state proposing the redesignation.

"Baseline Concentration" means that ambient concentration level which exists in the baseline area at the time of the applicable minor source baseline date.

"Major Modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Clean Air Act.

(1) Any net emissions increase that is significant for volatile organic compounds shall be considered significant for ozone.

(2) A physical change or change in the method of operation shall not include:

(a) routine maintenance, repair, and replacement;

(b) use of an alternative fuel or raw material by reason of an order under section 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation), or by reason of a natural gas curtailment plan pursuant to the Federal Power Act;

(c) use of an alternative fuel by reason of an order or rule under section 125 of the Clean Air Act;

(d) use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;

(e) use of an alternative fuel or raw material by a source which:

(i) the source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any federally enforceable permit condition; or

(ii) the source is approved to use;

(f) an increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition;

(g) any change in ownership at a source

(h) the addition, replacement or use of a pollution control project at an existing electric utility steam generating unit, unless the executive secretary determines that such addition, replacement, or use renders the unit less environmentally beneficial, or except:

(i) when the executive secretary has reason to believe that the pollution control project would result in a significant net increase in representative actual annual emissions of any criteria pollutant over levels used for that source in the most recent air quality impact analysis in the area conducted for the purpose of Title I of the Clean Air Act, if any, and

(ii) the executive secretary determines that the increase will cause or contribute to a violation of any national ambient air quality standard or PSD increment, or visibility limitation.

(i) the installation, operation, cessation, or removal of a temporary clean coal technology demonstration project, provided that the project complies with:

(i) the Utah State Implementation Plan; and

(ii) other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(j) the installation or operation of a permanent clean coal technology demonstration project that constitutes repowering, provided that the project does not result in an increase in the potential to emit of any regulated pollutant emitted by the unit. This exemption shall apply on a pollutant-by-pollutant basis.

(k) the reactivation of a very clean coal-fired electric utility steam generating unit.

"Major Source" means:

(1) any of the following sources of air pollutants which emits, or has the potential to emit, 100 tons per year or more of any pollutant subject to regulation under the Clean Air Act: Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), kraft pulp mills, portland cement plants, primary zinc smelters, iron

and steel mill plants, primary aluminum ore reduction plants, primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries, lime plants, phosphate rock processing plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion plants, sintering plants, secondary metal production plants, chemical process plants, fossil fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants, and charcoal production plants;

(2) any other source which emits, or has the potential to emit, 250 tons per year or more of any air pollutant; or

(3) a source which does not otherwise qualify as a major source as defined in this paragraph, but which is physically changed, which change itself would constitute a major source.

(4) a source which is major for volatile organic compounds is major for ozone.

(5) The fugitive emissions and fugitive dust of a stationary source shall not be included in determining for any of the purposes of this section whether it is a major stationary source, unless the source belongs to one of the following categories of stationary sources:

(a) Coal cleaning plants (with thermal dryers);
(b) Kraft pulp mills;
(c) Portland cement plants;
(d) Primary zinc smelters;
(e) Iron and steel mills;
(f) Primary aluminum ore reduction plants;
(g) Primary copper smelters;
(h) Municipal incinerators capable of charging more than 250 tons of refuse per day;
(i) Hydrofluoric, sulfuric, or nitric acid plants;
(j) Petroleum refineries;
(k) Lime plants;
(l) Phosphate rock processing plants;
(m) Coke oven batteries;
(n) Sulfur recovery plants;
(o) Carbon black plants (furnace process);
(p) Primary lead smelters;
(q) Fuel conversion plants;
(r) Sintering plants;
(s) Secondary metal production plants;

(t) Chemical process plants;

(u) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

(v) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

(w) Taconite ore processing plants;

(x) Glass fiber processing plants;

(y) Charcoal production plants;

(z) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input;

(aa) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Federal Clean Air Act.

R307-405-2. Area Designations.

All areas of the State shall be designated as Class I, II, or III.

(1) Pursuant to section 162(a) of the federal Clean Air Act the following areas are designated as mandatory Class I:

(a) Arches National Park

(b) Bryce Canyon National Park

(c) Canyonlands National Park

(d) Capitol Reef National Park

(e) Zion National Park

(2) Pursuant to section 162(b) of the federal Clean Air Act, all other areas of the State are designated as Class II unless redesignated as provided in R307-405-3 or are designated as nonattainment areas.

R307-405-3. Area Redesignation.

(1) Within the restrictions and requirements of this paragraph, the Board may submit to the Governor for decision a recommendation to redesignate areas from any class to any other class.

(2) In accordance with Section 162(a) of the federal Clean Air Act, areas designated as Class I under R307-405-2 may not be redesignated.

(3) In accordance with Section 164(a) of the federal Clean Air Act, the following areas may be redesignated only as Class I or II.

(a) An area which as of August 7, 1977, exceeded 10,000 acres in size and was a national monument, a national primitive area, a national preserve, a national recreation area, a national wild and scenic river, a national wildlife refuge, a national lakeshore or seashore; and

(b) A national park or national wilderness area established after August 7, 1977, which exceeds 10,000 acres in size.

(4) Except as provided in (2), (3) and (6) the Board may submit to the Governor for decision a recommendation to redesignate areas of the State as Class III if:

(a) There has been compliance with the requirements of (5) below.

(b) Such redesignation will not cause, or contribute to, concentrations of any air pollutant which exceed any maximum allowable increase permitted under the classification of any other area or any national ambient air quality standard; and

(c) Any permit application for any major source or major modification which could receive an approval order only if the area in question were redesignated as Class III, and any material submitted as part of that notice of intent were available, insofar as practicable, prior to any public hearing or redesignation.

In accordance with Section 164 of the federal Clean Air Act, redesignations to Class III may be approved by the Governor only after consultation with appropriate committees of the legislature and if units of local government representing a majority of the residents of the proposed area to be redesignated enact ordinances concurring in the redesignation.

(5) Prior to submittal to the Governor of a recommendation to redesignate any area:

(a) Notice shall be published in each daily newspaper in the affected area and written notice shall be made to local government units, other states, Indian governing bodies, Federal Land Managers whose lands may be affected by the proposed redesignation and public hearings shall be conducted in the affected areas. Such notice shall be made at least 30 days prior to the public hearing and include a statement of the availability of the discussion outlined in (b) below. Prior to the issuance of a notice under this paragraph respecting the redesignation of any Federal lands, a written notice shall be given to the appropriate Federal Land Manager who shall be afforded opportunity (not to exceed 60 days) to confer with the Board respecting the redesignation and to submit written comments and recommendations. In recommending redesignation of any area with respect to which a Federal Land Manager has submitted comments the Board shall publish a list of any inconsistency between such redesignation and such comments and recommendations together with the reasons for recommending

such redesignation against the recommendation of the Federal Land Manager; and

(b) A discussion of the reasons for the proposed redesignation, including a satisfactory description and analysis of the health, environmental, economic and social and energy effects of the proposed redesignation, will be prepared and made available for public inspection at least 30 days prior to the hearing. Any person who petitions the Board for redesignation of an area may be required to prepare and submit this analysis to the Board.

(6) Lands within the exterior boundaries of reservations of federally recognized Indian Tribes may be redesignated only by the appropriate Indian body as provided in Section 164 of the Clean Air Act.

R307-405-4. Increments and Ceilings.

(1) In Class I, II, or III areas, the maximum allowable increases in concentrations of sulfur dioxide, nitrogen dioxide and particulate matter over baseline concentrations of such pollutants are limited to the following:

TABLE

(1)Maximum Allowable Increase (ug/m3)

Pollutant	Class I	Class II	Class III
PM10:			
Annual Arithmetic Mean	4	17	34
24-hr. Maximum	8	30	60
Sulfur Dioxide:			
Annual Arithmetic Mean	2	20	40
24-hr. Maximum	5	91	182
3-hr. Maximum	25	512	700
Nitrogen Dioxide:			
Annual Arithmetic Mean	2.5	25	50

Note (1): At any one location, the maximum allowable increase for other than the annual period may be exceeded once each year. For any period other than the annual period, the applicable maximum allowable increase may be exceeded during one such period per year at any one location.

(2) Variances to Class I areas will be allowed only after compliance with the requirements of and within the increments provided in Section 165 of the federal Clean Air Act, or in the case of PM10 increments, only after compliance with the Title 40 of the Code of Federal Regulations, Section

51.166(p)(4) (as amended-see the June 3, 1993 Federal Register notice, 58 FR 31637) which is hereby incorporated by reference.

(3) In any area, no resultant concentration of any air pollutant shall exceed the concentration permitted under either the national secondary or primary ambient air quality standard whichever concentration is lowest for the pollutant for a period of exposure.

(4) Exclusions from increment consumption. The following concentrations shall be excluded in determining compliance with a maximum allowable increase:

(a) Concentrations attributable to the increase in emissions from sources which have converted from:

(i) the use of petroleum products, natural gas, or both by reason of an order in effect under sections 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974; or

(ii) using natural gas by reason of a natural gas curtailment plan in effect pursuant to the Federal Power Act, over the emissions from such sources before the effective date of such an order or plan.

No exclusion of such concentrations shall apply more than five years after the effective date of the order or the plan. If both an order and plan are applicable, no such exclusion shall apply more than five years after the later of such effective dates.

(b) Concentrations of PM10 attributable to the increase in emissions from construction or other temporary emission-related activities.

(c) Concentrations attributable to the temporary increase in emissions of sulfur dioxide, nitrogen oxides or PM10 from sources which are affected by plan revisions approved by EPA as meeting the criteria specified in 40 CFR 51.166(f)(4).

R307-405-5. Baseline Concentration and Date.

(1) Baseline concentration. A baseline concentration is determined for each pollutant for which a minor source baseline date is established and shall include:

(a) The actual emissions representative of sources in existence on the applicable minor source baseline date except as provided in (2) below;

(b) The allowable emissions of major sources which commence construction before the major source baseline date, but were not in operation by the applicable minor source baseline date.

(2) The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s):

(a) actual emissions from any major source on which construction commenced after the major source baseline date, and

(b) actual emissions increases and decreases at any source occurring after the minor source baseline date.

(3) Baseline date. The minor source baseline date is established for each pollutant for which increments or other equivalent measures have been established if:

(a) the area in which the proposed source or modification would construct is designated as attainment or unclassifiable under section 107(d)(i)(D) or (E) of the federal Clean Air Act for the pollutant on the date of its complete application under 40 CFR 52.21, or R307-405; and

(b) in the case of a major source the pollutant would be emitted in significant amounts, or, in the case of a major modification, there would be a significant net emissions increase of the pollutant. With respect to particulate matter, significant shall mean significant for PM10.

(4)(a) Any minor source baseline date established originally for increments of total suspended particulates shall remain in effect and shall apply for purposes of determining the amount of available PM10 increments, except that the executive secretary may rescind any such minor source baseline date where it can be shown to the executive secretary's satisfaction that the emissions increase from the major stationary source or the net emissions increase from the major modification responsible for triggering that date did not result in a significant amount of PM10 emissions.

(b) Any baseline area established originally for the increments of total suspended particulates shall remain in effect and shall apply for purposes of determining the amount of available PM10 increments, except that such baseline area shall not remain in effect if the executive secretary rescinds the corresponding minor source baseline date in accordance with(a) above.

R307-405-6. PSD Areas - New Sources and Modifications.

(1) Emission Limitations. Any source constructed or modified in a PSD area must meet all applicable emissions requirements of R307 and the Utah State Implementation Plan. A proposed source or modification which is not a major source or major modification may be approved without meeting the requirements in (2) below, provided such source meets all other applicable requirements of these regulations. The

emission limitations shall be stated as conditions of the approval order.

(2) Major Source and Major Modification Review. Every new major source or major modification must be reviewed by the Executive Secretary to determine the air quality impact of the source to include a determination whether the source will cause or contribute to a violation of the maximum allowable increases or the NAAQS in any area. The determination of air quality impact will be made as of the source's projected start-up date. Such determination shall take into account all allowable emissions of approved sources or modifications whether constructed or not, and, to the extent practicable, the cumulative effect on air quality of all sources and growth in the affected area.

(a) In addition to meeting all other requirements of these regulations, any major source or major modification which would be constructed in a PSD area, shall:

(i) Provide the following additional information with the notice of intent required pursuant to R307-401:

(A) An analysis of the air quality impact of the source or modification and a demonstration that allowable emissions increases from the source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), will not cause or contribute to a violation of any maximum allowable increase over the baseline concentration in any area or any NAAQS in any area.

(B) An analysis of ambient air quality in the affected area for each pollutant that a new source would have the potential to emit in a significant amount, and for each pollutant for which a modification would result in a significant net emissions increase. With respect to any such pollutant for which no NAAQS exists, the analysis shall contain such air quality monitoring data as the Executive Secretary determines is necessary to assess ambient air quality for that pollutant in any area that the emissions of that pollutant would affect. With respect to any such pollutant (other than non-methane hydrocarbons) for which such a NAAQS does exist, the analysis shall contain continuous air quality monitoring data gathered for purposes of determining whether emissions of that pollutant would cause or contribute to a violation of the standard or any maximum allowable increase in any area that the emissions of that pollutant would affect. In general, the continuous air quality monitoring data that is required shall have been gathered over a period of at least one year and shall represent at least the year preceding receipt of the notice of intent, except that, if the Executive Secretary determines

that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year (but not to be less than four months), the data that is required shall have been gathered over at least that shorter period. Any data used in the analysis must be gathered using EPA reference methods or equivalent and quality assurance procedures equivalent to 40 CFR Part 58, Appendix B. A monitoring plan will be submitted to the Executive Secretary for approval prior to data collection. The Executive Secretary may grant exceptions or modifications to these monitoring requirements when not inconsistent with federal law.

(C) Upon request of the Executive Secretary, the air quality impact of the source or modification, including meteorological and topographical data necessary to estimate such impact; and the air quality impact of any or all general commercial residential, industrial, and other growth which has occurred since the minor source baseline date in the area the source or modification would affect.

(D) An analysis of the air quality related impact of the source or modification including an analysis of the impairment to visibility, soils, and vegetation and the projected air quality impact from general commercial, residential, industrial, and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.

(ii) After construction of the source or modification, conduct such ambient air quality monitoring as the Executive Secretary determines may be necessary to establish the effect which the emissions from the source or modification may have on the air quality in any area.

(b) If the Executive Secretary finds that the emissions from a proposed major source or major modification would cause a violation of any maximum allowable increase over the baseline concentration in any area, the Executive Secretary shall approve the proposed source if and only if:

(i) the new source or modification is required to meet a more stringent emission limitation sufficient to avoid a violation of the maximum allowable increase and/or

(ii) the new source or modification has acquired sufficient offset to avoid a violation of the maximum allowable increase, and

(iii) the new emission limitations for the proposed source and for any affected existing sources are enforceable.

(c) If the Executive Secretary finds that the emissions from a proposed major source or major modification would

contribute to a known violation of any maximum allowable increase over the baseline concentration in any area, the Executive Secretary shall approve the proposed source if and only if:

(i) the new source or modification has acquired sufficient emission offset so as to provide a positive net air quality benefit in the affected area, and

(ii) any new emission limitations for affected existing sources are enforceable.

(3) The requirements of (2)(a) above shall not apply to a major source or major modification if:

(a) The source is a portable stationary source which has previously received a permit under this paragraph, and

(i) The owner or operator proposes to relocate the source and emissions of the source at the new location would be temporary; and

(ii) The emissions from the source would not exceed its allowable emissions; and

(iii) The emissions from the source would impact no Class I area and no area where an applicable increment is known to be violated;

(b) The source or modification would be a non-profit health or non-profit educational institution and the Board approves a request that it be exempt from those requirements.

(c) The source or modification would be a major source or major modification only if fugitive emission and fugitive dust, to the extent quantifiable, are considered in calculating the potential to emit of the source or modification and the source does not belong to any of the following categories:

(i) Coal cleaning plants (with thermal dryers);

(ii) Kraft pulp mills;

(iii) Portland cement plants;

(iv) Primary zinc smelters;

(v) Iron and steel mills;

(vi) Primary aluminum or reduction plants;

(vii) Primary copper smelters;

(viii) Municipal incinerators capable of charging more than 250 tons of refuse per day;

(ix) Hydrofluoric, sulfuric, or nitric acid plants;

(x) Petroleum refineries;

(xi) Lime plants;

(xii) Phosphate rock processing plants;

(xiii) Coke oven batteries;

(xiv) Sulfur recovery plants;

(xv) Carbon black plants (furnace process);

(xvi) Primary lead smelters;

(xvii) Fuel conversion plants;
(xviii) Sintering plants;
(xix) Secondary metal production plants;
(xx) Chemical process plants;
(xxi) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;
(xxii) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;
(xxiii) Taconite ore processing plants;
(xxiv) Glass fiber processing plants;
(xxv) Charcoal production plants;
(xxvi) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input;
(xxvii) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the federal Clean Air Act.

(d) With respect to a particular pollutant, the allowable emissions of that pollutant from the source, or the net emissions increase of that pollutant from the modification:

(i) would impact no Class I area and no area where an applicable increment is known to be violated, and

(ii) would be temporary.

(4) The requirements of (2)(a) above as they relate to any maximum allowable increase for a Class II area shall not apply to a major modification at a source that was in existence on March 1, 1978, if the net increase in allowable emissions for each pollutant from the modification after the application of best available control technology would be less than 50 tons per year.

(5)(a) The requirements of (2)(a)(i)(A) above pertaining to the impact analysis shall not apply to a source or modification with respect to any maximum allowable increase for nitrogen oxides if the owner or operator of the source or modification submitted a notice of intent before October 15, 1990, and the Executive Secretary subsequently determined that the notice of intent as submitted before that date was complete.

(b) The requirements of (2)(a)(i)(A) above concerning an analysis of the maximum allowable increase over the baseline concentration shall not apply to a stationary source or modification with respect to any maximum allowable increase for PM10 if the owner or operator of the source or modification submitted an application for a permit before December 15, 1994, and the executive secretary subsequently determined that the application as submitted before that date

was complete. Instead, the applicable requirements shall be with respect to the maximum allowable increases for total suspended particulates as in effect on the date the application was submitted. These increments were, for the annual geometric mean: 5, 19, and 37 micrograms/cubic meter for Class I, II and III areas respectively and, for the 24-hour maximum: 10, 37 and 75 micrograms/cubic meter for Class I, II and III areas respectively.

(6) Exemption - Monitoring Requirement

(a) The Executive Secretary may grant exceptions or modifications to the monitoring requirements in (2)(a)(i)(B) above which are not inconsistent with federal law.

(b) The Executive Secretary may exempt a stationary source or modification from the requirements of (2)(a)(i)(B) above with respect to monitoring for a particular pollutant if:

(i) The emissions increase of the pollutant from the new source or the net emissions increase of the pollutant from the modification would cause, in any area, air quality impacts less than the following amounts:

Carbon monoxide - 575 ug/m3, 8-hour average;
Nitrogen dioxide - 14 ug/m3, annual average;
PM10 - 10 micrograms/cubic meter, 24-hour average;
Sulfur dioxide - 13 ug/m3, 24-hour average;
Lead - 0.1 ug/m3, 24-hour average;
Mercury - 0.25 ug/m3, 24-hour average;
Beryllium - 0.0005 ug/m3, 24-hour average;
Ozone - No de minimis air quality level is provided for ozone. However, any proposed source or modification subject to PSD with net increase of 100 tons per year or more of volatile organic compounds subject to PSD would be required to perform an ambient impact analysis including the gathering of ambient air quality data;
Fluorides - 0.25 ug/m3, 24-hour average;
Vinyl chlorides - 15 ug/m3, 24-hour average;
Total reduced sulfur - 10 ug/m3, 1-hour average;
Hydrogen sulfide - 0.04 ug/m3, 1-hour average;
Reduced sulfur compounds - 10 ug/m3, 1-hour average; or

(ii) The concentrations of the pollutant in the area that the source or modification would affect are less than the concentrations listed or the pollutant is not listed in (i) above.

R307-405-7. Increment Violations.

Where the Board determines that an increment under R307-405-4 is violated, the Board shall promulgate a plan and implement regulations to eliminate the violation.

R307-405-8. Banking of Emission Offset Credit in PSD Areas.

Banking of emission offset credits in PSD areas will be permitted. To preserve banked emission reductions the Executive Secretary must identify them in either the Utah SIP or an order and shall provide a registry to identify the person, private entity, or government authority that has the right to use or allocate the banked emission reduction and to record any transfer of or lien on these rights.

KEY: air pollution, PSD, Class I area
July 12, 2001
Notice of Continuation August 11, 2003
19-2-104

EXHIBIT B

From: "Sean Phelan" <sphelan@westernresources.org>
To: <RSprott@utah.gov>, <JJenks@utah.gov>, <CStephens@utah.gov>, "Milka Radu...
Date: 11/2/2004 1:42 PM
Subject: GRAMA REQUEST
Attachments: WRA GRAMA Request - IPP and NEVCO.doc

Hi All,

Attached please find a GRAMA request for documents and EPA correspondence that post-date IPP and NEVCO's ITA. I realize that UDAQ may not be able to respond to this request before the close of the respective appeal deadlines. However, if UDAQ could quickly make available the revised top-down BACT analysis that includes IGCC and supercritical boilers and the revised PM10 modeling analysis, each referred to in IPP's Response to Comments Memo, it would be greatly appreciated.

Thank you,
Sean

Sean Phelan
Staff Attorney
Western Resource Advocates - Utah
-formerly Land and Water Fund of the Rockies
1473 South 1100 East, Suite F
Salt Lake City, UT 84105
ph - (801) 487-9911
fax - (801)486-4233

This communication may be privileged, confidential or otherwise exempt from disclosure.

November 3, 2002

Rick Sprott, Division Director
Department of Environmental Quality
Division of Air Quality
150 North 1950 West
Salt Lake City, UT 84116
(By Email: RSprott@utah.gov, JJenks@utah.gov, CStephens@utah.gov, and MilkaR@utah.gov and First-Class Mail)

Re: Request pursuant to Utah Governmental Records Access and Management Act (GRAMA), Utah Code § 63-2-101 et seq.

Dear Rick, John, Christian, and Milka,

As you know, the Utah Division of Air Quality (UDAQ) issued Approval orders to Sevier Power Company and Intermountain Power Service Corporation on October 12 and 15, 2004, respectively. Western Resource Advocates has been involved throughout the public permitting process for these coal fired power plants. In order to continue its participation in these processes, Western Resource Advocates makes the following request for records pursuant to Utah Governmental Records Access and Management Act (GRAMA), Utah Code § 63-2-101 *et seq.*:

1) Any and all records received, prepared, analyzed, considered or relied upon by UDAQ that relate in any way to UDAQ's issuance of Approval Order DAQE-AN2529001-04 for NEVCO Energy Company and/or UDAQ's response to comments associated with this Approval Order that post-date UDAQ's Intent to Approve dated February 27, 2004;

2) Any and all records, received, prepared, analyzed, considered or relied upon by UDAQ that relate in any way to UDAQ's issuance of Approval Order DAQE-AN0327010-04 for Intermountain Power Service Corporation and/or UDAQ's response to comments associated with this Approval Order that post-date UDAQ's Intent to Approve dated April 1, 2004. These records should include, *but not be limited to:*

- a revised top-down BACT analysis that includes IGCC and supercritical boiler, *see* UDAQ Response to Comments at 8,
- a revised PM10 modeling analysis submitted by IPP on August 26, 2004, *see* Response to Comments at 9;

3) Any and all correspondence, including email, between UDAQ and EPA regarding the permitting of Intermountain Power Service Corporation's proposed Intermountain Power Plant Unit 3 that post-date UDAQ's Intent to Approve dated April 1, 2004;

4) Any and all correspondence, including email, between UDAQ and EPA regarding the permitting of NEVCO Energy Company's proposed construction of a coal-fired power plant in Sigurd, Utah that post-date UDAQ's Intent to Approve dated February 27, 2004.

Although comments received during the public comment periods are responsive to this request, Western Resource Advocates does not need copies of these comments at this time. Thank you for your cooperation in this matter. Western Resource Advocates appreciates the time and effort it takes to fill this request. If you have any questions or concerns, please call me at 487-9911.

Best Regards,

Sean Phelan
Staff Attorney
Western Resource Advocates

EXHIBIT C

RECEIVED
NOV 18 2005
DAQ

FINLINSON & FINLINSON, PLLC
ATTORNEYS AT LAW
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Saratoga Springs, UT 84043
Telephone: (801)554-0765
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E-mail: f2fwcrf@msn.com

November 17, 2005

John D. Jenks, Engineer
Division of Air Quality
150 North 1959 West
PO Box 144820
Salt Lake City, UT 84114-4820

Re: Approval Order: Sevier Power Company's 270 MW Coal-Fired Power Plant, Sevier County- CDS A; ATT: PSD: NSPS, MACT, HAPs, Title IV Major, Title V Major
Project Code: DAQE-AN2529001-04

Dear John Jenks:

Our firm represents the Sevier Power Company and they have asked me to give you an update on what has happened since the Approval Order (the "AO") referenced above was issued on October 12, 2004. In short, before the ink on the AO was dry, it was appealed. A battle over standing was fought by the Parties before the Utah Air Quality Board (the "Board"). The Board determined that the Sierra Club and the Grand Canyon Trust did not have standing. These parties have appealed the Board's ruling on standing to the Court of Appeals. The Court of Appeals has denied motions from the Sierra Club and Grand Canyon Trust to enlarge the record and to stay the Board's formal adjudication of the Sevier County Citizens For Clean Air and Clean Water's Request For Agency Action. These events have taken place over the following time line:

1. October 12, 2004, The Executive Secretary issued the above mentioned Approval Order for the Sevier Power Company.

2. November 1, 2004, the Sevier County Citizens For Clean Air and Water (the "Sevier County Citizens"), filed a combined Petition For Standing to Intervene and a Request For Agency Action on the issuance of the AO. This document was filed with the Board on November 4, 2004.

3. November 12, 2004, the Sierra Club and Grand Canyon Trust (collectively the "Sierra Club") filed a Request For Agency Action and a Statement of Standing and Petition to Intervene.

4. January 4, 2005, PacifiCorp also filed a Petition to Intervene and a Statement of Standing.

5. January 6, 2005, the Board issued a "Notification of Further Proceedings" which established a schedule for briefing and reply briefing with a hearing before the Board set for March, which was subsequently reset for hearing on April 13, 2005. The parties filed extensive briefs pursuant to this schedule.

6. April 13, 2005, the Board conducted a hearing on the standing of each of the petitioning parties. The Executive Secretary and the Sevier Power Company were granted standing by Board Rule as the main parties. The Citizens For Sevier County, the Sierra Club and Utah Power may only intervene if granted permission by the Board. After the matter was fully heard, the Board determined that it would grant standing to the Sevier County Citizens, and deny standing to both the Sierra Club and Utah Power. The Board also granted amicus status to both the Sierra Club and Utah Power. The Board mentioned that it would put its ruling in written form and approve the written draft as the final order at its next meeting in May.

7. May 12, 2005, the Board, after a review of its written order prepared by Counsel Fred Nelson, adopted the May 12, 2005 as its written order which both granted and denied standing to the respective parties as mentioned above.

8. May 17, 2005, the Sierra Club filed its Petition for Review with the Court of Appeals seeking a reversal of the May 12th Board decision denying standing. The Sierra Club also filed a Motion to Stay the Sevier County Citizens' Request For Agency Action pending its appeal to the Court of Appeals.

9. June 1, 2005, the Board held a hearing on the Sierra Club's Motion to Stay the Request For Agency Action. After the matter had been briefed and all parties had presented information to the Board, it determined that it would not stay the remaining Request For Agency Action filed by the Sevier County Citizens. This order was signed by the Chairman of the Board on June 6, 2005. A schedule for Request For Agency review was adopted which provided a time for answers to be filed, discovery, motions, and a proposed hearing in December, 2005 was also adopted by the Board.

   Since the Sierra Club filed its Petition For Review with the Court of Appeals, there are now two different tracts of appeal being pursued by the Sierra Club and the Sevier County Citizens. I will attempt to weave both appeals into one common time line.

10. June 10, 2005 (DAQ), the Executive Secretary and the Sevier Power Company filed with the Board their response to the Citizens November 1, 2004 Request For Agency Action.

11. June 23, 2005 (COA), the Board filed with the Appellate Court its revised record index identifying the record of the Agency in making its decision to deny standing.

12. June 24, 2005 (COA), the Sevier Power Company filed its Motion to Intervene in the Court of Appeals review of the Board's decision on standing. Intervention was granted by the Court of Appeals.

13. July 1, 2005 (COA), the Sierra Club filed a Motion For A Stay Pending Review, with supporting memorandum, requesting the Court of Appeals to stay the administrative proceedings in the DAQ.

14. July 18, 2005 (COA), the Executive Secretary filed a Motion to Intervene in the Sierra Club's Motion for the Stay. Its request for intervene was granted by the Court and the Executive Secretary filed briefs in opposition to the Sierra Club's Motion for a Stay and Motion to Expand the Record.

15. July 19, 2005 (COA), the Sierra Club filed a Motion to Supplement Record with Supporting Memorandum, and a Motion for Enlargement of Time to File Opening Brief.

16. July 28, 2005 (COA), a mediation conference was held at the Court of Appeals. All of the parties were present and participated in the conference. Subsequently, the Court Appointed Mediator issued an order releasing the parties from further participation in mediation.

17. August 29, 2005 (COA), the Court of Appeals, after reviewing the Parties' memorandums on the various motions submitted by the Sierra Club, issued its order denying the Sierra Club's Motion to Stay and also denying the Sierra Club's Motion to Supplement the Record.

18. August 30, 2005 (COA), the Court of Appeals issued a scheduling order requiring the Sierra Club's Brief to be filed by October 3, 2005. It was filed timely. The Executive Secretary and the Sevier Power Company filed their responsive briefs on November 2, 2005. The Sierra Club has an opportunity to file one more brief by December 2, 2005. After all of the briefs have been filed, the Court of Appeals will review the briefs and determine whether a hearing should be scheduled. They did not hold a hearing before denying the two previous motions of the Sierra Club. There could still be a hearing after the briefing is completed by December 2, 2005 and then after the hearing, the Court would then issue its decision on the Board's denial of standing to the Sierra Club. A final decision from the COA is still a number of months in the future.

19. September 23, 2005 (DAQ), the Executive Secretary served a set of interrogatories and request for the production of documents on the Sevier County Citizens.

20. October 3, 2005 (DAQ), the Executive Secretary filed a Motion to Compel because of the alleged failure of the Sevier County Citizens group to respond to the Interrogatories and

Requests For Production of Documents.

21. November 2, 2005 (DAQ), the Board held a hearing on the Executive Secretary's Motion to Compel. The Parties were present and submitted information to the Board about the lack of Discovery response from the Sevier County Citizens Group. After hearing from all parties, the Board granted the Motion to Compel and entered a written Order Regarding The Executive Secretary's Motion to Compel Discovery.

22. January 2006 (DAQ), this would be the earliest that a hearing on the Request For Agency Action could be held; however, at this meeting the Parties, including the Executive Secretary and the Sevier Power Company, may request the Board to rule on Preliminary Motions, and that the actual hearing, if necessary may more likely be scheduled for the February 2006 Board Meeting, with a written order being approved at the March 2006 Board Meeting. A decision made by the Board on the Request For Approval can be appealed by any party to the Court of Appeals. A Court of Appeal review of the final agency action, could take up to another year, once the appeal has been filed.

The uncertainty associated with the formal adjudicative process based on both Requests For Agency Action, coupled with the appeal of the decision denying standing to the Court of Appeals has required the Sevier Power Company to put on hold the construction of the power plant authorized by the October 12, 2004 Approval Order.

The Sevier Power Company requests the Executive Secretary to hold in abeyance the running of the 18 month period for construction to start from the date that the first Request For Agency Action was filed (November 1, 2004) until the formal adjudication process, including any appeals, is concluded and the review process confirms that the Sevier Power Company has a valid Approval Order. Please advise if further action on the part of Sevier Power Company is necessary in order to obtain the abeyance period requested. If you have any question, please call me at the number mentioned above.

Sincerely,

FINLINSON & FINLINSON, PLLC

Fred W. Finlinson

FWF
cc: The Sevier Power Company

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Attorneys for the Executive Secretary of the Utah Air Quality Board

BEFORE THE UTAH AIR QUALITY BOARD

In the Matter of: Unit 3, Intermountain Power Service Corporation, Millard County, Utah DAQE-AN0327010-04	EXECUTIVE SECRETARY'S MEMORANDUM IN OPPOSITION TO SIERRA CLUB'S MOTION FOR LEAVE TO AMEND REQUEST FOR AGENCY ACTION

The Executive Secretary of the Utah Air Quality Board ("Executive Secretary") hereby files this Memorandum in Opposition to Sierra Club's Motion for Leave to Amend its Request for Agency Action dated February 16, 2007. The Executive Secretary opposes the amendment because (1) Sierra Club's motion is untimely, and (2) the Executive Secretary complied with applicable law. Accordingly, the Executive Secretary respectfully requests that Sierra Club's motion be denied.

INTRODUCTION

Sierra Club seeks leave from the Utah Air Quality Board (the "Board") to amend its Request for Agency Action ("RFA") dated November 16, 2004. Sierra Club's RFA contests the Approval Order issued by the Executive Secretary to Intermountain Power Service Corporation ("IPSC") on October 15, 2004. Sierra Club now seeks leave to amend its RFA to add a cause of action which would provide an entirely new basis for invalidating the Approval Order, wholly distinct from the cause of action in the original RFA. Sierra Club's proposed amendment claims that according to state and federal regulation, the IPSC Approval Order is now invalid because

more than 18 months (from the date of issuance of the AO) have passed without IPSC beginning construction on the project, and without an extension by the Executive Secretary. This proposed amendment is completely distinct from all the other claims in the RFA. As the Executive Secretary will demonstrate, the Board should deny Sierra Club's proposed amendment because 1) Sierra Club's motion is untimely, and 2) the factual basis for Sierra Club's new cause of action is erroneous.

ARGUMENT

A. Amendment Should not be Allowed Because It Would Not Withstand a Motion to Dismiss

It is well settled that "[l]eave to file an amended complaint should be denied when movant seeks to assert a new claim that is illegally insufficient or futile." Andalex Resources, Inc. v. Myers, 871 P.2d 1041, 1046 (Utah Ct. App. 1994). Moreover, "'. . . . a court may deny a motion to amend as futile if the proposed amendment would not withstand a motion to dismiss . . . . .'" Jensen v. IHC Hospitals, Inc., 82 P.3d 1076, 1102 (Utah 2003), *quoting* Acker v. Burlington N. and Santa Fe Ry., Co., 215 F.R.D. 645, 647 (D.Kan.2003).

Sierra Club's proposed new would be futile because 1) the claim is time-barred and 2) Sierra Club's alleged factual basis for the new cause of action is erroneous.

1. Sierra Club's Claim is Untimely

Sierra Club filed its RFA pursuant to Utah Admin. Code R307-103-3. Subsection (3) of that rule provides in pertinent part that "[a] request for agency action . . . shall, to be timely, be received for filing within 30 days of the issuance of the initial order or notice of violation." It is further well-settled that "[w]hen a cause of action set forth in an amended pleading is new, different, and distinct from that originally set up, there is not relation back [to the original action], and the amendment is equivalent to the filing of a new action. Peterson v. Union Pac. R.

Co., 8 P.2d 627, 630 (Utah 1932). Since Sierra Club's new claim would be introducing a "new, different, and distinct" cause of action, for timeliness purposes it needs to be treated as if it were a separate Request for Agency Action. Acknowledging the 30 day filing requirement under R307-103-3, Sierra Club asserts that this requirement does not apply because its new claim is based on an alleged "automatic expiration of the permit, and not to a particular action of the Executive Secretary," and that therefore, there is no time limitation for Sierra Club to make such a filing. *Id.* In its Motion for Summary Judgment, Sierra Club bases this argument on the faulty proposition that 40 C.F.R. § 52.21(r) applies to the Approval Order. That federal regulation states in pertinent part that "[a]pproval to construct shall become invalid if construction is not commenced within 18 months of receipt of such approval . . . ." 40 C.F.R. § 52.21(r)(2).

Sierra Club's proposed amendment alleges that "twenty eight months have passed since the Executive Secretary signed the Approval Order for the proposed plant," and that "the AO is now invalid, having expired automatically on or about April 15, 2006." *See* Sierra Club proposed First Amended Request for Agency Action at 21. This contention has no merit because the Board did not incorporate this federal regulation into the Utah Air Rules (at R307-405-19(1)) until the March 2006 Air Quality Board meeting, to become effective in June 2006.[1] Because this federal regulation was not part of the Utah Air Rules at the time the Executive Secretary issued the Approval Order, the Approval Order was not subject to the federal regulation.

Consequently, Sierra Club is left only with Utah Air Rule R307-401-18 and Condition No. 8 of the Approval Order, both of which endow the Executive Secretary with broad discretion to revoke the Approval Order if construction has not commenced after 18 months. Since neither of these provisions mandate an automatic expiration of the approval order, there would be no

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[1]See Exhibit A. This exhibit contains the amendments proposed to the Utah Air Quality Board at the March 2006 Air Quality Board meeting. It includes both the original rules and the proposed amendments that were ultimately adopted by the Board.

automatic expiration of the Approval Order as Sierra Club asserts. Since Sierra Club cannot rely on an inapplicable federal regulation, its only avenue to contest an alleged violation of R307-401-18 is only through a new request for agency action, and thus, the 30 day filing requirement.

Sierra Club seeks to justify its delay in acting on the alleged violation by claiming that it was not on notice of the Executive Secretary's actions until it received the administrative record on February 15, 2007. This argument is wholly unpersuasive. The administrative record is only as broad as the allegations in Sierra Club's RFA, which (up until its current effort to amend) did not contain any cause of action relating to any 18 month review. Anything beyond those allegations is not relevant to the claims of Sierra Club's RFA, and thus is not properly part of the administrative record. Because there would be no reasonable expectation that the administrative record would contain any documentation concerning a 18 month review, Sierra Club's claim that it could not act without first having reviewed the administrative record is without justification.

Furthermore, nothing prevented Sierra Club from inquiring through a government records (GRAMA) request back in April 2006, particularly considering its familiarity with the rules and its past actions in this case. For example, in October 2004, Sierra Club filed a lengthy GRAMA request with the Division of Air Quality to obtain documents it believed relevant to its case. *See* Exhibit B, attached. Sierra Club's proactive past actions are inconsistent with its current assertion that it was powerless to determine the facts underlying its new cause of action until after it had received the administrative record. Further, even allowing Sierra Club the benefit of the doubt in April 2006 because its status as a party was on appeal, the Utah Supreme Court issued its standing decision on November 21, 2006, and Sierra Club did not file its motion to amend until February 16, 2007, some 87 days after it was granted standing. Under either timeline, Sierra Club's amendment is time-barred as a matter of law.

2. <u>The Executive Secretary Complied with the Applicable State Rule</u>

In addition to being untimely, Sierra Club's claim would not survive a motion to dismiss because there is no basis in law or fact. While the federal regulation providing for automatic expiration of the permit does not apply, there is no disagreement that Utah Admin. Code R307-401-18, does apply. That regulation states:

> Approval orders issued by the Executive Secretary in accordance with the provisions of R307-401 will be reviewed 18 months after the date of issuance to determine the status of construction, installation, modification, relocation, or establishment. If a continuous plan of construction, installation, modification, relocation or establishment is not proceeding, the Executive Secretary may revoke the approval order.

In its Motion for Summary Judgment, Sierra Club simply misstates the facts. As previously indicated, Sierra Club's motion is the result of Sierra Club's unjustifiable reliance on an administrative record which would not be expected to contain information on the 18 month review. A review of the relevant time period demonstrates that the Executive Secretary did in fact comply with R307-401-18. On January 13, 2006, IPSC sent a letter to the Executive Secretary explaining the current status of the IPSC project. In that letter, IPSC outlined its belief that its permit conditions were valid and requested an extension of the 18 month period. The Executive Secretary reviewed this letter and responded affirmatively. *See* Exhibit C, attached. Therefore, the Executive Secretary was provided with the necessary knowledge of the "status of construction, installation, modification, relocation, or establishment" of the IPSC project. Utah Admin. Code R307-401-18. Consequently, the Executive Secretary used his discretion in not revoking the Approval Order. Therefore, Sierra Club's assertion that the Executive Secretary failed to comply with the regulation is without a factual basis.

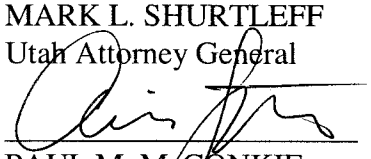
CONCLUSION

Based on the foregoing, the Executive Secretary opposes the amendment because the proposed amendment is without legal or factual basis and would not withstand a motion to

dismiss. Accordingly, the Executive Secretary respectfully requests that Sierra Club's Motion to amend its Request for Agency Action be denied

Dated this 5th day of March, 2007.

MARK L. SHURTLEFF
Utah Attorney General



PAUL M. McCONKIE
CHRISTIAN C. STEPHENS
Assistant Attorneys General

CERTIFICATE OF SERVICE

I hereby certify that on the 5th day of March, 2007, a true and correct copy of the foregoing Executive Secretary's Motion for Partial Judgment on the Pleadings was mailed, postage prepaid, and/or emailed to the following:

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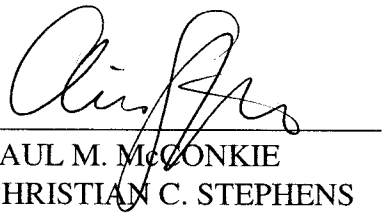

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EXHIBIT A

State of Utah

Department of Environmental Quality

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Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

Air Quality Board
John M. Veranth, *Chair*
Ernest E. Wessman , *Vice-Chair*
Nan Bunker
Stead Burwell
Jerry D. Grover
James R. Horrocks
Scott Lawson
Dianne R. Nielson
Wayne M. Samuelson
JoAnn B. Seghini
Don Sorensen
Richard W. Sprott,
Executive Secretary

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

DAQ-007-06

UTAH AIR QUALITY BOARD MEETING

Working lunch session will be held prior
12:00-1:00 p.m.

168 North 1950 West (Bldg #2) Room 101

FINAL AGENDA

Wednesday, March 8, 2006
1:30 p.m.

168 North 1950 West (Bldg #2) Room 101

I. Call-to-Order.

II. Date of the Next Air Quality Board Meeting: April 5, 2006.

III. Approval of the Minutes for February's Board Meeting.

IV. Approve Location and Travel for Sevier Power Hearing. Presented By Rick Sprott.

V. Final Adoption: Repeal and Re-enact R307-405, Permits: Major Sources in Attainment or Unclassified Areas (PSD); Amend R307-110-9 and State Implementation Plan Section VIII, Prevention of Significant Deterioration. Presented by Colleen Delaney and Jim Schubach.

VI. Final Adoption: Repeal and Re-enact R307-401, Permits: New and Modified Sources. Presented by Colleen Delaney and Jim Schubach.

VII. Final Adoption: Amend R307-410, Permits: Emission Impact Analysis. Presented by Colleen Delaney and Jim Schubach.

VIII. Propose for Public Comment: Repeal R307-413, Permits: Exemptions and Special Provisions; Amend R307-101-2 Definitions; Amend R307-325, Davis and Salt Lake Counties and Ozone Nonattainment Areas: Ozone Provisions. Presented By Colleen Delaney and Jim Schubach.

IX. Informational Items
A. $PM_{2.5}$ Proposed Standards. Presented by Cheryl Heying.
B. Recent SIP Approvals. Presented By Jan Miller.
C. Compliance. Presented by Jeff Dean.
D. HAPS. Presented by Robert Ford.
E. Monitoring. Presented by Bob Dalley.

In compliance with the American with Disabilities Act, individuals with special needs (including auxiliary communicative aids and services) should contact Charlene Lamph, Office of Human Resources at (801) 536-4413 (TDD 536-4414).

R307. Environmental Quality, Air Quality.
R307-405. Permits: Prevention of Significant Deterioration of Air Quality (PSD).[

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R307-405-1. Purpose.

This rule implements the federal Prevention of Significant Deterioration (PSD) permitting program for major sources and major modifications in attainment areas and maintenance areas as required by 40 CFR 51.166. This rule does not include the routine maintenance, repair and replacement provisions that were stayed by the DC Circuit Court of Appeals on December 23, 2003, pending appeal. This rule does not include the clean unit and pollution control project provisions that were vacated by the DC Circuit Court of Appeals on June 24, 2005. This rule supplements, but does not replace, the permitting requirements of R307-401.

R307-405-2. Applicability.

(1) Except as provided in (2), the provisions of 40 CFR 52.21(a)(2), effective March 3, 2003, are hereby incorporated by reference.

(2)(a) The provisions in 40 CFR 52.21(a)(2)(iv)(e) are not incorporated by reference.

(b) The last sentence in 40 CFR 52.21(a)(2)(iv)(f) is not incorporated by reference.

(c) The provisions in 40 CFR 52.21(a)(2)(vi) are not incorporated by reference.

(3) Notwithstanding the exemptions in R307-401, any source that is subject to R307-405 is subject to the requirement to obtain an approval order in R307-401-5 through 8.

R307-405-3. Definitions.

(1) Except as provided in (2)below, the definitions contained in 40 CFR 52.21(b), effective March 3, 2003, are hereby incorporated by reference.

(2) "Air Quality Related Values," as used in analyses under 40 CFR 52.21(p) that is incorporated by reference in R307-405-17, means those special attributes of a Class I area, assigned by a federal land manager, that are adversely affected by air quality.

(3)(a)(i) "Major Source Baseline Date" means:

(A) in the case of particulate matter:

(I) for Davis, Salt Lake, Utah and Weber Counties, the date that EPA approves the PM10 maintenance plan that was adopted by the Board on July 6, 2005;

(II) for all other areas of the State, January 6, 1975;

(B) in the case of sulfur dioxide:

(I) for Salt Lake County, the date that EPA approves the sulfur dioxide maintenance plan that was adopted by the Board on January 5, 2005;

(II) for all other areas of the State, January 6, 1975; and

(C) in the case of nitrogen dioxide, February 8, 1988.

(ii) "Minor Source Baseline Date" means the earliest date after the trigger date on which a major stationary source or a major modification subject to 40 CFR 52.21 or R307-405 submits a complete application under the relevant regulations. The trigger date is:

(A) In the case of particulate matter and sulfur dioxide, August 7, 1977, and

(B) in the case of nitrogen dioxide, February 8, 1988.

(iii) The baseline date is established for each pollutant for which increments or other equivalent measures have been established if:

(A) the area in which the proposed source or modification would construct is designated as attainment or unclassifiable under section 107(d)(i)(D) or (E) of the Act for the pollutant on the date of its complete application under 40 CFR 52.21 or R307-405; and

(B) in the case of a major stationary source, the pollutant would be emitted in significant amounts, or, in the case of a major modification, there would be a significant net emissions increase of the pollutant.

(iv) Any minor source baseline date established originally for the TSP increments shall remain in effect and shall apply for purposes of determining the amount of available PM10 increments, except that the executive secretary shall rescind a minor source baseline date where it can be shown, to the satisfaction of the executive secretary, that the emissions increase from the major stationary source, or net emissions increase from the major modification, responsible for triggering that date did not result in a significant amount of PM10 emissions.

(b) In the definition of "baseline area" in 40 CFR 52.21(b)(15)(ii)(b) insert the words "or R307-405" after "Is subject to 40 CFR 52.21".

(c) "Reviewing Authority" means the executive secretary.

(d)(i) The term "Administrator" shall be changed to "executive secretary" throughout R307-405, except as provided in (ii).

(ii) The term "Administrator" shall be changed to "EPA Administrator" in the following incorporated sections:

(A) 40 CFR 52.21(b)(17),

(B) 40 CFR 52.21(b)(37)(i),

(C) 40 CFR 52.21(b)(43),

(D) 40 CFR 52.21(b)(48)(ii)(c),

(E) 40 CFR 52.21(b)(50)(i),

(F) 40 CFR 52.21(l)(2),

(G) 40 CFR 52.21(p)(2), <u>and</u>

(H) [~~the first reference to Administrator in 40 CFR 52.21(y)(4)(i),~~

~~(I) the second reference to Administrator in 40 CFR 52.21(y)(7), and~~

~~(J)~~]40 CFR 51.166(q)(2)(iv).

(e) The definition of "emissions unit" in 40 CFR 52.21(b)(7), effective January 6, 2004, is hereby incorporated by reference.

(f) The definition of "replacement unit" in 40 CFR 52.21(b)(33), effective January 6, 2004, is hereby incorporated by reference.

(g) The following paragraphs that refer to clean units and pollution control projects are not incorporated by reference:

(i) 40 CFR 52.21(b)(2)(iii)(h),

(ii) 40 CFR 52.21(b)(3)(iii)(b),

(iii) 40 CFR 52.21(b)(3)(vi)(d),

(iv) 40 CFR 52.21(b)(32), and

(v) 40 CFR 52.21(b)(42).

([~~3~~]4) "Heat input" means heat input as defined in 40 CFR 52.01(g).

([~~4~~]5) "Title V permit" means any permit or group of permits covering a Part 70 source that is issued, renewed, amended, or revised pursuant to R307-415.

([~~5~~]6) "Title V Operating Permit Program" means R307-415.

([~~6~~]7) The definition of "Good Engineering Practice (GEP) Stack Height" as defined in R307-410 shall apply in this rule.

([~~7~~]8) The definition of "Dispersion Technique" as defined in R307-410 shall apply in this rule.

R307-405-4. Area Designations.

(1) Pursuant to section 162(a) of the federal Clean Air Act, the following areas are designated as mandatory Class I areas:

(a) Arches National Park,

(b) Bryce Canyon National Park,

(c) Canyonlands National Park,

(d) Capitol Reef National Park, and

(e) Zion National Park.

(2) Pursuant to section 162(b) of the federal Clean Air Act, all other areas in Utah are designated as Class II unless designated as nonattainment areas.

(3) No areas in Utah are designated as Class III.

R307-405-5. Area Redesignation.

Any person may petition the Board to change the classification of an area designated under R307-405-4, except for mandatory Class I areas designated under R307-405-4(1).

(1) The petition shall contain a discussion of the reasons for the proposed redesignation, including a satisfactory description and analysis of the health, environmental, economic and social and energy effects of the proposed re[~~s~~]designation.

(2) The petition shall contain a demonstration that the proposed redesignation meets the criteria outlined in Section VIII of the State Implementation Plan and 40 CFR 51.166(e) and (g).

R307-405-6. Ambient Air Increments.

The provisions of 40 CFR 52.21(c), effective March 3, 2003, are hereby incorporated by reference.

R307-405-7. Ambient Air Ceilings.

The provisions of 40 CFR 52.21(d), effective March 3, 2003, are hereby incorporated by reference.

R307-405-8. Exclusions from Increment Consumption.

(1) The following concentrations shall be excluded in determining compliance with a maximum allowable increase:

(a) concentrations attributable to the increase in emissions from stationary sources which have converted from the use of petroleum products, natural gas, or both by reason of an order in effect under section 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) over the emissions from such sources before the effective date of such an order;

(b) concentrations attributable to the increase in emissions from sources which have converted from using natural gas by reason of a natural gas curtailment plan in effect pursuant to the Federal Power Act over the emissions from such sources before the effective date of such plan;

(c) concentrations of particulate matter attributable to the increase in emissions from construction or other temporary emission-related activities of new or modified sources;

(d) the increase in concentrations attributable to new sources outside the United States over the concentrations attributable to existing sources which are included in the baseline concentration; and

(e) concentrations attributable to the temporary increase in emissions of sulfur dioxide, particulate matter, or nitrogen dioxides from stationary sources which are affected by plan revisions approved by the EPA Administrator as meeting the criteria specified in 40 CFR 51.166(f)(4). The temporary increase shall not exceed 2 years in duration unless a longer time is approved by the EPA Administrator. This exclusion is not renewable.

(2) No exclusion of concentration under (1)(a) or (b) above shall apply more than five years after the effective date of the order to which paragraph (1)(a) refers or the plan to which paragraph (1)(b) refers, whichever is applicable. If both such order and plan are applicable, no such exclusion shall apply more than five years after the later of such effective dates.

(3) No exclusion under (1)(e) shall apply to an emission increase from a stationary source which would:

(a) impact a Class I area or an area where an applicable increment is known to be violated; or

(b) cause or contribute to a violation of the national ambient air quality standards.

R307-405-9. Stack Heights.

The provisions of 40 CFR 52.21(h), effective March 3, 2003, are hereby incorporated by reference.

R307-405-10. Exemptions.

(1) The provisions of 40 CFR 52.21(i)(1)(vi) through (viii), effective March 3, 2003, are hereby incorporated by reference.

(2) The provisions of 40 CFR 52.21(i)(2) through (5), effective March 3, 2003, are hereby incorporated by reference.

R307-405-11 Control Technology Review.

The provisions of 40 CFR 52.21(j), effective March 3, 2003, are hereby incorporated by reference.

R307-405-12. Source Impact Analysis.

The provisions of 40 CFR 52.21(k), effective March 3, 2003, are hereby incorporated by reference.

R307-405-13. Air Quality Models.

The provisions of 40 CFR 52.21(l), effective March 3, 2003, are hereby incorporated by reference.

R307-405-14. Air Quality Analysis.

(1) The provisions of 40 CFR 52.21(m)(1)(i) through (iv), (vi), and (viii), effective March 3, 2003, are hereby incorporated by reference.

(2) The provisions of 40 CFR 52.21(m)(2) and (3), effective March 3, 2003, are hereby incorporated by reference.

R307-405-15. Source Information.

The provisions of 40 CFR 52.21(n), effective March 3, 2003, are hereby incorporated by reference.

R307-405-16. Additional Impact Analysis.

The provisions of 40 CFR 52.21(o), effective March 3, 2003, are hereby incorporated by reference.

R307-405-17. Sources Impacting Federal Class I Areas: Additional Requirements.

(1) The provisions of 40 CFR 52.21(p), effective March 3, 2003, are hereby incorporated by reference.

(2) The executive secretary will transmit to the EPA Administrator a copy of each permit application relating to a major stationary source or major modification and provide notice to the EPA Administrator of every action related to the consideration of such permit.

R307-405-18. Public Participation.

(1) Except as provided in (2), the provisions of 40 CFR 51.166(q)(1) and (2), effective March 3, 2003, are hereby incorporated by reference.

(2) The phrase "within a specified time period" in 40 CFR 51.166(q)(1) shall be replaced with the phrase "within 30 days of receipt of the PSD permit application".

R307-405-19. Source Obligation.

(1) Except as provided in (2) below, the provisions of 40 CFR 52.21(r), effective March 3, 2003, are hereby incorporated by reference.

(2)[~~(a)~~] The parenthetical phrase in the first sentence in 40 CFR 52.21(r)(6) shall be changed to read "(other than projects at a source with a PAL)."[

~~(b) The reference to "70.4(b)(3)(viii) of this chapter" in 40 CFR 52.21(r)(7) shall be changed to "R307-415-7i".~~]

R307-405-20. Innovative Control Technology.

(1) Except as provided in (2), the provisions of 40 CFR 52.21(v), effective March 3, 2003, are hereby incorporated by reference.

(2)(a) The reference to "40 CFR 124.10" in 40 CFR 52.21(v)(1) shall be changed to "R307-405-18".

(b) 40 CFR 52.21(v)(2) shall be changed to read "The executive secretary shall, with the consent of the governors of other affected states, determine that the source or modification may employ a system of innovative control technology, if:".

R307-405-21. Actuals PALs.

(1) Except as provided in (3), the provisions of 40 CFR 52.21(aa)(1) through (5) and (7) through (15), effective March 3, 2003, are hereby incorporated by reference.

(2) The provisions of 40 CFR 52.21(aa)(6), effective January 6, 2004, are hereby incorporated by reference.

(3)(a) The reference to "51.165(a)(3)(ii) of this chapter" in 40 CFR 52.21(aa)(4)(ii) shall be changed to "R307-403".

(b) The reference to "51.165(a)(3)(ii) of this chapter" in 40 CFR 52.21(aa)(8)(ii)(2) shall be changed to "R307-403".

(c) The references to "70.6(a)(3)(iii)(B) of this chapter" in 40 CFR 52.21(aa)(14)(ii) shall be changed to "R307-415-6a(3)(c)(ii)".

(d) The date of "March 3, 2003" in 40 CFR 52.21(aa)(15)(i) and (ii) shall be changed to "the effective date of this rule".

R307-405-22. Banking of Emission Offset Credit in PSD Areas.

Banking of emission offset credits in PSD areas will be permitted. To preserve banked emission reductions the executive secretary must identify them in either the Utah SIP or an order. The executive secretary will provide a registry to identify the person, private entity, or government authority that has the right to use or allocate the banked emission reduction and to record any transfer of or lien on these rights.

KEY: air pollution, PSD, Class I area
2006
Notice of Continuation August 11, 2003
19-2-104

R307. Environmental Quality, Air Quality.
R307-405. Permits: Prevention of Significant Deterioration of Air Quality (PSD).
R307-405-1. Definitions.

The following additional definitions apply to R307-405:

"Baseline Area" means any intrastate area (and every part thereof) designated as attainment or unclassifiable under Section 107(d)(1)(D) or (E) of the federal Clean Air Act in which the major source or major modification establishing the minor source baseline date would construct or would have an air quality impact equal to or greater than 1 ug/m3 (annual average) of the pollutant for which the minor source baseline date is established.

(1) Area redesignations under section 107(d)(1) (D) or (E) of the federal Clean Air Act cannot intersect or be smaller than the area of impact of any major stationary source or major modification which:

(a) Establishes a minor source baseline date; or

(b) Is subject to 40 CFR 52.21 or R307-405, and would be constructed in the same state as the state proposing the redesignation.

"Baseline Concentration" means that ambient concentration level which exists in the baseline area at the time of the applicable minor source baseline date.

"Major Modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Clean Air Act.

(1) Any net emissions increase that is significant for volatile organic compounds shall be considered significant for ozone.

(2) A physical change or change in the method of operation shall not include:

(a) routine maintenance, repair, and replacement;

(b) use of an alternative fuel or raw material by reason of an order under section 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation), or by reason of a natural gas curtailment plan pursuant to the Federal Power Act;

(c) use of an alternative fuel by reason of an order or rule under section 125 of the Clean Air Act;

(d) use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;

(e) use of an alternative fuel or raw material by a source which:

(i) the source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any federally enforceable permit condition; or

(ii) the source is approved to use;

(f) an increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition;

(g) any change in ownership at a source

(h) the addition, replacement or use of a pollution control project at an existing electric utility steam generating unit, unless the executive secretary determines that such addition, replacement, or use renders the unit less environmentally beneficial, or except:

(i) when the executive secretary has reason to believe that the pollution control project would result in a significant net increase in representative actual annual emissions of any criteria pollutant over levels used for that source in the most recent air quality impact analysis in the area conducted for the purpose of Title I of the Clean Air Act, if any, and

(ii) the executive secretary determines that the increase will cause or contribute to a violation of any national ambient air quality standard or PSD increment, or visibility limitation.

(i) the installation, operation, cessation, or removal of a temporary clean coal technology demonstration project, provided that the project complies with:

(i) the Utah State Implementation Plan; and

(ii) other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(j) the installation or operation of a permanent clean coal technology demonstration project that constitutes repowering, provided that the project does not result in an increase in the potential to emit of any regulated pollutant emitted by the unit. This exemption shall apply on a pollutant-by-pollutant basis.

(k) the reactivation of a very clean coal-fired electric utility steam generating unit.

"Major Source" means:

(1) any of the following sources of air pollutants which emits, or has the potential to emit, 100 tons per year or more of any pollutant subject to regulation under the Clean Air Act: Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), kraft pulp mills, portland cement plants, primary zinc smelters, iron

and steel mill plants, primary aluminum ore reduction plants, primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries, lime plants, phosphate rock processing plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion plants, sintering plants, secondary metal production plants, chemical process plants, fossil fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants, and charcoal production plants;

(2) any other source which emits, or has the potential to emit, 250 tons per year or more of any air pollutant; or

(3) a source which does not otherwise qualify as a major source as defined in this paragraph, but which is physically changed, which change itself would constitute a major source.

(4) a source which is major for volatile organic compounds is major for ozone.

(5) The fugitive emissions and fugitive dust of a stationary source shall not be included in determining for any of the purposes of this section whether it is a major stationary source, unless the source belongs to one of the following categories of stationary sources:

(a) Coal cleaning plants (with thermal dryers);
(b) Kraft pulp mills;
(c) Portland cement plants;
(d) Primary zinc smelters;
(e) Iron and steel mills;
(f) Primary aluminum ore reduction plants;
(g) Primary copper smelters;
(h) Municipal incinerators capable of charging more than 250 tons of refuse per day;
(i) Hydrofluoric, sulfuric, or nitric acid plants;
(j) Petroleum refineries;
(k) Lime plants;
(l) Phosphate rock processing plants;
(m) Coke oven batteries;
(n) Sulfur recovery plants;
(o) Carbon black plants (furnace process);
(p) Primary lead smelters;
(q) Fuel conversion plants;
(r) Sintering plants;
(s) Secondary metal production plants;

(t) Chemical process plants;

(u) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

(v) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

(w) Taconite ore processing plants;

(x) Glass fiber processing plants;

(y) Charcoal production plants;

(z) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input;

(aa) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Federal Clean Air Act.

R307-405-2. Area Designations.

All areas of the State shall be designated as Class I, II, or III.

(1) Pursuant to section 162(a) of the federal Clean Air Act the following areas are designated as mandatory Class I:

(a) Arches National Park

(b) Bryce Canyon National Park

(c) Canyonlands National Park

(d) Capitol Reef National Park

(e) Zion National Park

(2) Pursuant to section 162(b) of the federal Clean Air Act, all other areas of the State are designated as Class II unless redesignated as provided in R307-405-3 or are designated as nonattainment areas.

R307-405-3. Area Redesignation.

(1) Within the restrictions and requirements of this paragraph, the Board may submit to the Governor for decision a recommendation to redesignate areas from any class to any other class.

(2) In accordance with Section 162(a) of the federal Clean Air Act, areas designated as Class I under R307-405-2 may not be redesignated.

(3) In accordance with Section 164(a) of the federal Clean Air Act, the following areas may be redesignated only as Class I or II.

(a) An area which as of August 7, 1977, exceeded 10,000 acres in size and was a national monument, a national primitive area, a national preserve, a national recreation area, a national wild and scenic river, a national wildlife refuge, a national lakeshore or seashore; and

(b) A national park or national wilderness area established after August 7, 1977, which exceeds 10,000 acres in size.

(4) Except as provided in (2), (3) and (6) the Board may submit to the Governor for decision a recommendation to redesignate areas of the State as Class III if:

(a) There has been compliance with the requirements of (5) below.

(b) Such redesignation will not cause, or contribute to, concentrations of any air pollutant which exceed any maximum allowable increase permitted under the classification of any other area or any national ambient air quality standard; and

(c) Any permit application for any major source or major modification which could receive an approval order only if the area in question were redesignated as Class III, and any material submitted as part of that notice of intent were available, insofar as practicable, prior to any public hearing or redesignation.

In accordance with Section 164 of the federal Clean Air Act, redesignations to Class III may be approved by the Governor only after consultation with appropriate committees of the legislature and if units of local government representing a majority of the residents of the proposed area to be redesignated enact ordinances concurring in the redesignation.

(5) Prior to submittal to the Governor of a recommendation to redesignate any area:

(a) Notice shall be published in each daily newspaper in the affected area and written notice shall be made to local government units, other states, Indian governing bodies, Federal Land Managers whose lands may be affected by the proposed redesignation and public hearings shall be conducted in the affected areas. Such notice shall be made at least 30 days prior to the public hearing and include a statement of the availability of the discussion outlined in (b) below. Prior to the issuance of a notice under this paragraph respecting the redesignation of any Federal lands, a written notice shall be given to the appropriate Federal Land Manager who shall be afforded opportunity (not to exceed 60 days) to confer with the Board respecting the redesignation and to submit written comments and recommendations. In recommending redesignation of any area with respect to which a Federal Land Manager has submitted comments the Board shall publish a list of any inconsistency between such redesignation and such comments and recommendations together with the reasons for recommending

such redesignation against the recommendation of the Federal Land Manager; and

(b) A discussion of the reasons for the proposed redesignation, including a satisfactory description and analysis of the health, environmental, economic and social and energy effects of the proposed redesignation, will be prepared and made available for public inspection at least 30 days prior to the hearing. Any person who petitions the Board for redesignation of an area may be required to prepare and submit this analysis to the Board.

(6) Lands within the exterior boundaries of reservations of federally recognized Indian Tribes may be redesignated only by the appropriate Indian body as provided in Section 164 of the Clean Air Act.

R307-405-4. Increments and Ceilings.

(1) In Class I, II, or III areas, the maximum allowable increases in concentrations of sulfur dioxide, nitrogen dioxide and particulate matter over baseline concentrations of such pollutants are limited to the following:

TABLE

(1)Maximum Allowable Increase (ug/m3)

Pollutant	Class I	Class II	Class III
PM10:			
Annual Arithmetic Mean	4	17	34
24-hr. Maximum	8	30	60
Sulfur Dioxide:			
Annual Arithmetic Mean	2	20	40
24-hr. Maximum	5	91	182
3-hr. Maximum	25	512	700
Nitrogen Dioxide:			
Annual Arithmetic Mean	2.5	25	50

Note (1): At any one location, the maximum allowable increase for other than the annual period may be exceeded once each year. For any period other than the annual period, the applicable maximum allowable increase may be exceeded during one such period per year at any one location.

(2) Variances to Class I areas will be allowed only after compliance with the requirements of and within the increments provided in Section 165 of the federal Clean Air Act, or in the case of PM10 increments, only after compliance with the Title 40 of the Code of Federal Regulations, Section

51.166(p)(4) (as amended-see the June 3, 1993 Federal Register notice, 58 FR 31637) which is hereby incorporated by reference.

(3) In any area, no resultant concentration of any air pollutant shall exceed the concentration permitted under either the national secondary or primary ambient air quality standard whichever concentration is lowest for the pollutant for a period of exposure.

(4) Exclusions from increment consumption. The following concentrations shall be excluded in determining compliance with a maximum allowable increase:

(a) Concentrations attributable to the increase in emissions from sources which have converted from:

(i) the use of petroleum products, natural gas, or both by reason of an order in effect under sections 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974; or

(ii) using natural gas by reason of a natural gas curtailment plan in effect pursuant to the Federal Power Act, over the emissions from such sources before the effective date of such an order or plan.

No exclusion of such concentrations shall apply more than five years after the effective date of the order or the plan. If both an order and plan are applicable, no such exclusion shall apply more than five years after the later of such effective dates.

(b) Concentrations of PM10 attributable to the increase in emissions from construction or other temporary emission-related activities.

(c) Concentrations attributable to the temporary increase in emissions of sulfur dioxide, nitrogen oxides or PM10 from sources which are affected by plan revisions approved by EPA as meeting the criteria specified in 40 CFR 51.166(f)(4).

R307-405-5. Baseline Concentration and Date.

(1) Baseline concentration. A baseline concentration is determined for each pollutant for which a minor source baseline date is established and shall include:

(a) The actual emissions representative of sources in existence on the applicable minor source baseline date except as provided in (2) below;

(b) The allowable emissions of major sources which commence construction before the major source baseline date, but were not in operation by the applicable minor source baseline date.

(2) The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s):

(a) actual emissions from any major source on which construction commenced after the major source baseline date, and

(b) actual emissions increases and decreases at any source occurring after the minor source baseline date.

(3) Baseline date. The minor source baseline date is established for each pollutant for which increments or other equivalent measures have been established if:

(a) the area in which the proposed source or modification would construct is designated as attainment or unclassifiable under section 107(d)(i)(D) or (E) of the federal Clean Air Act for the pollutant on the date of its complete application under 40 CFR 52.21, or R307-405; and

(b) in the case of a major source the pollutant would be emitted in significant amounts, or, in the case of a major modification, there would be a significant net emissions increase of the pollutant. With respect to particulate matter, significant shall mean significant for PM10.

(4)(a) Any minor source baseline date established originally for increments of total suspended particulates shall remain in effect and shall apply for purposes of determining the amount of available PM10 increments, except that the executive secretary may rescind any such minor source baseline date where it can be shown to the executive secretary's satisfaction that the emissions increase from the major stationary source or the net emissions increase from the major modification responsible for triggering that date did not result in a significant amount of PM10 emissions.

(b) Any baseline area established originally for the increments of total suspended particulates shall remain in effect and shall apply for purposes of determining the amount of available PM10 increments, except that such baseline area shall not remain in effect if the executive secretary rescinds the corresponding minor source baseline date in accordance with(a) above.

R307-405-6. PSD Areas - New Sources and Modifications.

(1) Emission Limitations. Any source constructed or modified in a PSD area must meet all applicable emissions requirements of R307 and the Utah State Implementation Plan. A proposed source or modification which is not a major source or major modification may be approved without meeting the requirements in (2) below, provided such source meets all other applicable requirements of these regulations. The

emission limitations shall be stated as conditions of the approval order.

(2) Major Source and Major Modification Review. Every new major source or major modification must be reviewed by the Executive Secretary to determine the air quality impact of the source to include a determination whether the source will cause or contribute to a violation of the maximum allowable increases or the NAAQS in any area. The determination of air quality impact will be made as of the source's projected start-up date. Such determination shall take into account all allowable emissions of approved sources or modifications whether constructed or not, and, to the extent practicable, the cumulative effect on air quality of all sources and growth in the affected area.

(a) In addition to meeting all other requirements of these regulations, any major source or major modification which would be constructed in a PSD area, shall:

(i) Provide the following additional information with the notice of intent required pursuant to R307-401:

(A) An analysis of the air quality impact of the source or modification and a demonstration that allowable emissions increases from the source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), will not cause or contribute to a violation of any maximum allowable increase over the baseline concentration in any area or any NAAQS in any area.

(B) An analysis of ambient air quality in the affected area for each pollutant that a new source would have the potential to emit in a significant amount, and for each pollutant for which a modification would result in a significant net emissions increase. With respect to any such pollutant for which no NAAQS exists, the analysis shall contain such air quality monitoring data as the Executive Secretary determines is necessary to assess ambient air quality for that pollutant in any area that the emissions of that pollutant would affect. With respect to any such pollutant (other than non-methane hydrocarbons) for which such a NAAQS does exist, the analysis shall contain continuous air quality monitoring data gathered for purposes of determining whether emissions of that pollutant would cause or contribute to a violation of the standard or any maximum allowable increase in any area that the emissions of that pollutant would affect. In general, the continuous air quality monitoring data that is required shall have been gathered over a period of at least one year and shall represent at least the year preceding receipt of the notice of intent, except that, if the Executive Secretary determines

that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year (but not to be less than four months), the data that is required shall have been gathered over at least that shorter period. Any data used in the analysis must be gathered using EPA reference methods or equivalent and quality assurance procedures equivalent to 40 CFR Part 58, Appendix B. A monitoring plan will be submitted to the Executive Secretary for approval prior to data collection. The Executive Secretary may grant exceptions or modifications to these monitoring requirements when not inconsistent with federal law.

(C) Upon request of the Executive Secretary, the air quality impact of the source or modification, including meteorological and topographical data necessary to estimate such impact; and the air quality impact of any or all general commercial residential, industrial, and other growth which has occurred since the minor source baseline date in the area the source or modification would affect.

(D) An analysis of the air quality related impact of the source or modification including an analysis of the impairment to visibility, soils, and vegetation and the projected air quality impact from general commercial, residential, industrial, and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.

(ii) After construction of the source or modification, conduct such ambient air quality monitoring as the Executive Secretary determines may be necessary to establish the effect which the emissions from the source or modification may have on the air quality in any area.

(b) If the Executive Secretary finds that the emissions from a proposed major source or major modification would cause a violation of any maximum allowable increase over the baseline concentration in any area, the Executive Secretary shall approve the proposed source if and only if:

(i) the new source or modification is required to meet a more stringent emission limitation sufficient to avoid a violation of the maximum allowable increase and/or

(ii) the new source or modification has acquired sufficient offset to avoid a violation of the maximum allowable increase, and

(iii) the new emission limitations for the proposed source and for any affected existing sources are enforceable.

(c) If the Executive Secretary finds that the emissions from a proposed major source or major modification would

contribute to a known violation of any maximum allowable increase over the baseline concentration in any area, the Executive Secretary shall approve the proposed source if and only if:

(i) the new source or modification has acquired sufficient emission offset so as to provide a positive net air quality benefit in the affected area, and

(ii) any new emission limitations for affected existing sources are enforceable.

(3) The requirements of (2)(a) above shall not apply to a major source or major modification if:

(a) The source is a portable stationary source which has previously received a permit under this paragraph, and

(i) The owner or operator proposes to relocate the source and emissions of the source at the new location would be temporary; and

(ii) The emissions from the source would not exceed its allowable emissions; and

(iii) The emissions from the source would impact no Class I area and no area where an applicable increment is known to be violated;

(b) The source or modification would be a non-profit health or non-profit educational institution and the Board approves a request that it be exempt from those requirements.

(c) The source or modification would be a major source or major modification only if fugitive emission and fugitive dust, to the extent quantifiable, are considered in calculating the potential to emit of the source or modification and the source does not belong to any of the following categories:

(i) Coal cleaning plants (with thermal dryers);

(ii) Kraft pulp mills;

(iii) Portland cement plants;

(iv) Primary zinc smelters;

(v) Iron and steel mills;

(vi) Primary aluminum or reduction plants;

(vii) Primary copper smelters;

(viii) Municipal incinerators capable of charging more than 250 tons of refuse per day;

(ix) Hydrofluoric, sulfuric, or nitric acid plants;

(x) Petroleum refineries;

(xi) Lime plants;

(xii) Phosphate rock processing plants;

(xiii) Coke oven batteries;

(xiv) Sulfur recovery plants;

(xv) Carbon black plants (furnace process);

(xvi) Primary lead smelters;

(xvii) Fuel conversion plants;
(xviii) Sintering plants;
(xix) Secondary metal production plants;
(xx) Chemical process plants;
(xxi) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;
(xxii) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;
(xxiii) Taconite ore processing plants;
(xxiv) Glass fiber processing plants;
(xxv) Charcoal production plants;
(xxvi) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input;
(xxvii) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the federal Clean Air Act.

(d) With respect to a particular pollutant, the allowable emissions of that pollutant from the source, or the net emissions increase of that pollutant from the modification:

(i) would impact no Class I area and no area where an applicable increment is known to be violated, and

(ii) would be temporary.

(4) The requirements of (2)(a) above as they relate to any maximum allowable increase for a Class II area shall not apply to a major modification at a source that was in existence on March 1, 1978, if the net increase in allowable emissions for each pollutant from the modification after the application of best available control technology would be less than 50 tons per year.

(5)(a) The requirements of (2)(a)(i)(A) above pertaining to the impact analysis shall not apply to a source or modification with respect to any maximum allowable increase for nitrogen oxides if the owner or operator of the source or modification submitted a notice of intent before October 15, 1990, and the Executive Secretary subsequently determined that the notice of intent as submitted before that date was complete.

(b) The requirements of (2)(a)(i)(A) above concerning an analysis of the maximum allowable increase over the baseline concentration shall not apply to a stationary source or modification with respect to any maximum allowable increase for PM10 if the owner or operator of the source or modification submitted an application for a permit before December 15, 1994, and the executive secretary subsequently determined that the application as submitted before that date

was complete. Instead, the applicable requirements shall be with respect to the maximum allowable increases for total suspended particulates as in effect on the date the application was submitted. These increments were, for the annual geometric mean: 5, 19, and 37 micrograms/cubic meter for Class I, II and III areas respectively and, for the 24-hour maximum: 10, 37 and 75 micrograms/cubic meter for Class I, II and III areas respectively.

(6) Exemption - Monitoring Requirement

(a) The Executive Secretary may grant exceptions or modifications to the monitoring requirements in (2)(a)(i)(B) above which are not inconsistent with federal law.

(b) The Executive Secretary may exempt a stationary source or modification from the requirements of (2)(a)(i)(B) above with respect to monitoring for a particular pollutant if:

(i) The emissions increase of the pollutant from the new source or the net emissions increase of the pollutant from the modification would cause, in any area, air quality impacts less than the following amounts:

Carbon monoxide - 575 ug/m3, 8-hour average;
Nitrogen dioxide - 14 ug/m3, annual average;
PM10 - 10 micrograms/cubic meter, 24-hour average;
Sulfur dioxide - 13 ug/m3, 24-hour average;
Lead - 0.1 ug/m3, 24-hour average;
Mercury - 0.25 ug/m3, 24-hour average;
Beryllium - 0.0005 ug/m3, 24-hour average;
Ozone - No de minimis air quality level is provided for ozone. However, any proposed source or modification subject to PSD with net increase of 100 tons per year or more of volatile organic compounds subject to PSD would be required to perform an ambient impact analysis including the gathering of ambient air quality data;
Fluorides - 0.25 ug/m3, 24-hour average;
Vinyl chlorides - 15 ug/m3, 24-hour average;
Total reduced sulfur - 10 ug/m3, 1-hour average;
Hydrogen sulfide - 0.04 ug/m3, 1-hour average;
Reduced sulfur compounds - 10 ug/m3, 1-hour average; or

(ii) The concentrations of the pollutant in the area that the source or modification would affect are less than the concentrations listed or the pollutant is not listed in (i) above.

R307-405-7. Increment Violations.

Where the Board determines that an increment under R307-405-4 is violated, the Board shall promulgate a plan and implement regulations to eliminate the violation.

R307-405-8. Banking of Emission Offset Credit in PSD Areas.

Banking of emission offset credits in PSD areas will be permitted. To preserve banked emission reductions the Executive Secretary must identify them in either the Utah SIP or an order and shall provide a registry to identify the person, private entity, or government authority that has the right to use or allocate the banked emission reduction and to record any transfer of or lien on these rights.

KEY: air pollution, PSD, Class I area
July 12, 2001
Notice of Continuation August 11, 2003
19-2-104

EXHIBIT B

From: "Sean Phelan" <sphelan@westernresources.org>
To: <RSprott@utah.gov>, <JJenks@utah.gov>, <CStephens@utah.gov>, "Milka Radu...
Date: 11/2/2004 1:42 PM
Subject: GRAMA REQUEST
Attachments: WRA GRAMA Request - IPP and NEVCO.doc

Hi All,

Attached please find a GRAMA request for documents and EPA correspondence that post-date IPP and NEVCO's ITA. I realize that UDAQ may not be able to respond to this request before the close of the respective appeal deadlines. However, if UDAQ could quickly make available the revised top-down BACT analysis that includes IGCC and supercritical boilers and the revised PM10 modeling analysis, each referred to in IPP's Response to Comments Memo, it would be greatly appreciated.

Thank you,
Sean

Sean Phelan
Staff Attorney
Western Resource Advocates - Utah
-formerly Land and Water Fund of the Rockies
1473 South 1100 East, Suite F
Salt Lake City, UT 84105
ph - (801) 487-9911
fax - (801)486-4233

This communication may be privileged, confidential or otherwise exempt from disclosure.

November 3, 2002

Rick Sprott, Division Director
Department of Environmental Quality
Division of Air Quality
150 North 1950 West
Salt Lake City, UT 84116
(By Email: RSprott@utah.gov, JJenks@utah.gov, CStephens@utah.gov, and MilkaR@utah.gov and First-Class Mail)

Re: Request pursuant to Utah Governmental Records Access and Management Act (GRAMA), Utah Code § 63-2-101 et seq.

Dear Rick, John, Christian, and Milka,

As you know, the Utah Division of Air Quality (UDAQ) issued Approval orders to Sevier Power Company and Intermountain Power Service Corporation on October 12 and 15, 2004, respectively. Western Resource Advocates has been involved throughout the public permitting process for these coal fired power plants. In order to continue its participation in these processes, Western Resource Advocates makes the following request for records pursuant to Utah Governmental Records Access and Management Act (GRAMA), Utah Code § 63-2-101 *et seq.*:

1) Any and all records received, prepared, analyzed, considered or relied upon by UDAQ that relate in any way to UDAQ's issuance of Approval Order DAQE-AN2529001-04 for NEVCO Energy Company and/or UDAQ's response to comments associated with this Approval Order that post-date UDAQ's Intent to Approve dated February 27, 2004;

2) Any and all records, received, prepared, analyzed, considered or relied upon by UDAQ that relate in any way to UDAQ's issuance of Approval Order DAQE-AN0327010-04 for Intermountain Power Service Corporation and/or UDAQ's response to comments associated with this Approval Order that post-date UDAQ's Intent to Approve dated April 1, 2004. These records should include, *but not be limited to:*

- a revised top-down BACT analysis that includes IGCC and supercritical boiler, *see* UDAQ Response to Comments at 8,
- a revised PM10 modeling analysis submitted by IPP on August 26, 2004, *see* Response to Comments at 9;

3) Any and all correspondence, including email, between UDAQ and EPA regarding the permitting of Intermountain Power Service Corporation's proposed Intermountain Power Plant Unit 3 that post-date UDAQ's Intent to Approve dated April 1, 2004;

4) Any and all correspondence, including email, between UDAQ and EPA regarding the permitting of NEVCO Energy Company's proposed construction of a coal-fired power plant in Sigurd, Utah that post-date UDAQ's Intent to Approve dated February 27, 2004.

Although comments received during the public comment periods are responsive to this request, Western Resource Advocates does not need copies of these comments at this time. Thank you for your cooperation in this matter. Western Resource Advocates appreciates the time and effort it takes to fill this request. If you have any questions or concerns, please call me at 487-9911.

Best Regards,

Sean Phelan
Staff Attorney
Western Resource Advocates

EXHIBIT C

State of Utah

Department of Environmental Quality

Dianne R. Nielson, Ph.D.
Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

FILE COPY

DAQE-GN0327010-06

January 27, 2006

Reed Searle
Intermountain Power Agency
10653 South River Front Parkway, Suite 120
South Jordan, Utah 84095

Re: Review of the Approval Order DAQE-AN0327010-04 dated October 15, 2004.

Dear Mr. Searle:

The Utah Division of Air Quality (UDAQ) has received your letter dated January 13, 2006 in accordance with Approval Order number DAQE-AN0327010-04.

UDAQ reviewed your AO in accordance with the R307-401-11 of the Utah Administrative Code (UAC) and prepared the attached Memo.

Please note that Executive Secretary will not exercise the right to revoke the above referenced AO as outlined in R307-401-11. However, by April 15, of 2008, IPSC shall again notify the Executive Secretary in writing on the status of the construction and/or installation. At that time the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11, UAC.

Sincerely,

Richard W. Sprott, Executive Secretary
Utah Air Quality Board

RWS: MR:kw
Attachment: GN0327010A-06

State of Utah

Department of Environmental Quality

Dianne R. Nielson, Ph.D.
Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

FILE COPY

DAQE-GN0327010A-06

MEMORANDUM

TO: Intermountain Power Service Corporation (IPSC) Project Source File (Site ID 10327)

THROUGH: Richard W. Sprott, Executive Secretary RWS 1/24/06
Regg Olsen, Permitting Branch Manager
Rusty Ruby, NSR Section Manager, R 1/24/06

FROM: Milka Radulovic, NSR Engineer

SUBJECT: Review of the Approval Order (AO) for IPSC Unit #3 number DAQE-AN0327010-04 in Accordance with Condition 8 and Utah Administrative Code (UAC) Rule 307-401-11

DATE: January 23, 2006

We reviewed the IPSC letter dated January 13, 2006, sent to UDAQ in accordance with AO Condition 8. Reviewing the letter UDAQ finds that IPSC is engaged in many project development activities at substantial expense in excess of 5 million dollars.

UDAQ also finds that on November 12, 2004, IPSC petitioned the Utah Air Quality Board for review of Condition 24 in the AO dated October 15, 2004. Settlement negotiations took place between UDAQ and IPSC, resulting in a Joint Stipulation. The Joint Stipulation was approved by the Order of the Air Quality Board on September 7, 2005. The AO incorporates the terms of the Joint Stipulation. In addition, on November 15, 2004, Western Resources Advocates appealed the AO and action on the appeal is pending. These actions caused significant delay and necessitated an extension of the construction program.

For these reasons the Executive Secretary will not exercise the right to revoke the above referenced AO as outlined in R307-401-11. However, by April 15, of 2008, IPSC shall again notify the Executive Secretary in writing on the status of the construction and/or installation. At that time the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11, UAC.

Intermountain Power Agency

January 13, 2006

Rick Sprott
Executive Secretary
Utah Division of Air Quality
150 North 1950 West
Salt Lake City, UT 84116

Re: IPA Unit 3 Request for 24 Month Extension

Dear Mr. Sprott:

The Intermountain Power Service Company ("IPSC") submits this request for a twenty-four (24) month extension of the period within which to commence construction under Approval Order #DAQE-AN0327010-04. The AO was issued by the Utah Department of Air Quality ("UDAQ") on October 15, 2004 for the addition of a new Unit 3 at the Intermountain Power Generating Station. The request will extend the time period to commence construction from April 15, 2006 until April 15, 2008.

Construction Status

General Condition #8 of the AO indicates that IPSC shall notify you in writing on the status of construction and/or installation of Unit 3 within 18 months of the issuance of the AO. The development participants have been actively engaged in many project development activities at great expense, including the following:

- developing joint ownership arrangements
- preparing agreements to govern the use of facilities in common with units 1 and 2
- preparing a joint operating agreement covering units 1, 2 and 3
- exploring fuel supply strategies
- initiating engineering and other technical work prerequisite to the procurement of equipment.

The development participants have spent in excess of $5 million dollars in preparatory work for the Unit 3 project and will continue to vigorously pursue these ongoing activities leading to the selection of an owner's engineer, preparation of

10653 South River Front Parkway, Suite 120, South Jordan, Utah 84095
(801) 938-1333 Fax (801) 938-1330

detailed specifications for construction, and procurement of necessary equipment and on-site construction activities commencing before April 15, 2008.

Extension Requests

Extension requests for major coal plants and other complex facilities are not uncommon. The Wyoming DEQ recently granted a 24 month extension to the Two Elks project and the North Dakota Department of Health granted a 36 month extension for a North Dakota PSD permit. Other states have granted extensions as well.

AO Timing

It is, quite literally, not possible to complete all of the tasks necessary to develop, design and construct a coal-fired power plant of this size in the 18 month window prescribed in the AO. For that reason, AO General Condition #8 and the underlying requirements contemplate a process to extend the AO as necessary.

In addition to the amount of time required to complete the development tasks noted above, there are long lead times for many construction-related activities and significant timing needs associated with the financial complexities surrounding a project with construction costs of over $1 Billion-a complicated 950 MW Unit 3 project with unique features, i.e. engineering designs, financing, and ownership. In addition, the legal challenge to AO and the subsequent appeal of the Air Board's decision has taken a tremendous amount of time and resources. Until that legal challenge is completed, the AO does not have the certainty necessary to make final construction plans and finalize financing.

Discussions among the development participants likewise require large amounts of time, along with the time to complete the resource planning requirements of individual development participants (including the SB 26 mandated PSC approval process for PacifiCorp). For all of these reasons, IPSC believes that adequate justification exists to extend the 18 month timeframe to commence construction for an added 24 months. The need is even greater because one of the original development participants unexpectedly withdrew from the project—the Los Angeles Department of Water & Power (LADWP). This in and of

itself caused significant delay and is an added reason why an extension is necessary.

BACT Update

IPSC and the development participants are mindful of the need to assure that there have not been any significant changes in Best Available Control Technology ("BACT") determinations since the AO for Unit 3 originally was issued. In that regard, a study by CH2MHill has gathered BACT determinations for facilities similar to the new Unit 3 at the Intermountain Power Generating Station, issued since October 15, 2004. See Attachment A for a list of the BACT determinations updated since October 15, 2004. This study reveals that no new pollution control technologies have been determined as BACT for facilities similar to Unit 3. Based on this review, IPSC has determined that no new technologies or emissions levels have been established as BACT that would require any revisions to the AO.

Accordingly, IPSC respectfully requests that a twenty-four (24) month extension be granted to allow IPSC sufficient time to further develop, design and begin construction on the new Unit 3. Thank you for your attention to this matter, and please contact me with any questions.

Sincerely,

Reed T. Searle

Reed T. Searle
General Manager

Enclosures
Cc: Doug Hunter, UAMPS
Ernie Wessman, PacifiCorp

Attachment A

The Approval Order for IPP Unit 3 was issued on October 15, 2004. Since that issuance, some new air quality construction permits have been issued for pulverized coal fired utility boilers. Enclosed is an updated listing of these permits similar to the one that was included in the appendix of the original Notice of Intent for IPP 3.

The permits that were issued subsequent to October 15, 2004 and were reviewed are Comanche Unit 3, Weston Unit 4, WYGEN Unit 2, Newmont Unit 1, as well as the re-issuance of the Bull Mountain Roundup Units 1 and 2 permit.

CH2M HILL has reviewed these permits and has determined that for NOx, all of these permits are in the range of 0.07 to 0.08 pounds per million BTU 30 day rolling average. The IPP AO is 0.07 pounds per million BTU 30 day rolling average. Therefore there is no justification to revise the IPP NOx limit.

For SO_2, all of these permits are in the range of 0.09 to 0.10 pounds per million BTU 30 day rolling average. The IPP AO is 0.09 pounds per million BTU 30 day rolling average and 0.10 24 hour average. Therefore there is no justification to revise the IPP SO2 limit.

For CO the permits range from 0.13 to 0.15 pounds per million BTU with the Comanche permit at 0.13 pounds per million BTU eight hour rolling average during normal operation but a much higher limit of 0.30 pounds per million BTU during startup. The Newmont permit is for a shorter averaging time (24 hour rolling average) while the IPP AO CO limit is for 30 day rolling average of 0.15 pounds per million BTU. The IPP AO is well in the range of the most recent permits and therefore we see no reason to revise the IPP CO limit.

For VOC, the permits range from 0.0027 to 0.01 pounds per million BTU. The Newmont permit is for 8.1 pounds per hour which is equivalent to 0.004 pounds per million BTU at full load. The IPP AO is 0.0027 pounds per million BTU which is the lowest BACT limit. Therefore we see no reason to revise the IPP VOC limit.

For PM_{10}, the permits range from 0.012 to 0.18 pounds PM_{10} filterable per million BTU. The IPP AO is at 0.012 pounds per million BTU for a three test run average. This is the lowest BACT limit of all the permits and therefore we see no reason to revise the IPP PM_{10} limit.

For H_2SO_4, the permits range from .001 to 0.005 pounds per million BTU. The IPP AO limits H_2SO_4 emissions to .0044 pounds per million BTU 24 hour block average. The Newmont limit is 0.001 pounds per million BTU (2.04 pounds per hour) using a dry lime FGD system while IPP Unit 3 will use a wet limestone scrubber. Given this difference in sulfur control technology the Newmont permit limit for H_2SO_4 is inapplicable. The remaining permits range from 0.0042 to .005 and the IPP is in this range. Therefore we see no reason to revise the IPP H_2SO_4 limit.

TABLE E-1
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for CO
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Proper Boiler Design and Operat	not given	0.15	lb/MMBTU		12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Combustion Control	not given	0.15	lb/MMBtu		7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Combustion Control	not given	0.13	lb/MMBtu	8-hour Rolling avg.	7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Good Combustion Controls	not given	0.15	lb/MMBTU	24-hour	5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Combustion Control	not given	0.15 3,399	lb/MMBTU tons/yr	1-Day 12-month Rolling avg.	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	Combustion Control	not given	0.15 3,000	lb/MMBTU lbs/hr	30-day Rolling avg. 8-hour Block avg.	10/15/2004

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:
- RBLC Determinations added during or after October 15, 2004
- SIC Code: 4911
- Process Type Code: 11.100 - Coal Combustion

TABLE E-2
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for VOC
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Proper Boiler Design and Operation	not given	0.003	lb/MMBtu		12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Combustion Control	not given	0.01	lb/MMBtu		7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Combustion Control	not given	0.0036	lb/MMBtu		7/5/2005
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Combustion Control	not given	0.0036 81.6	lb/MMBTU tons/yr	1-Day 12-month Rolling avg.	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr		not given	0.0027	lb/MMBTU	3 stack test run average	10/15/2004

Notes:

TABLE E-3
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for PM
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Fabric Filter	not given	0.012	lb/MMBTU	24-hour	5/05/2005 No. AP4911-1349

Notes:

TABLE E-4
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for PM_{10}
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Fabric Filter Baghouse	not given	0.012	lb/MMBTU		12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Fabric Filter	not given	0.012	lb/MMBtu		7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Fabric Filter	not given	0.012 0.020	lb/MMBtu	3-hour Rolling avg (filterable) 3-hour Rolling avg (filterable & condensable)	7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Fabric Filter	not given	0.012	lb/MMBTU	24-hour	5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Fabric Filter	not given	0.018	lb/MMBTU	3-hour Rolling avg.	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	Fabric Filer	not given	0.012 221	lb/MMBTU lbs/hr	3 stack test run avg. 24-hour Block avg	10/15/2004

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:

TABLE E-5
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for Lead
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit	Averaging Period	Permit Date and Permit No.

Notes:

TABLE E-6
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for Fluorides
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit	Averaging Period	Permit Date and Permit No.
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant	1	Coal Fired Boiler 2030 MMBTU/HR	Dry Spray Scrubber and Fabric Filter	not given	1.17 lbs/hr		5/05/2005 No. AP4911-1349

Notes:

TABLE E-7
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for SO_2
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Dry Flue Gas Desulfurization System	90%	0.15	lb/MMBtu	1-hour	12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Dry Lime FGD	not given	0.10 0.12	lb/MMBTU lb/MMBTU	30-day Rolling avg. 3-hour Block avg.	7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Dry Lime FGD	not given	0.1	lb/MMBtu	30-day Rolling	7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Lime Spray Dryer Scrubber	not given	0.09 0.065	lb/MMBTU lb/MMBTU	24-hour (Coal S >= 0.45%) - 95% removal eff, 30-day period 24-hour (Coal S <0.45%) - 91% removal eff, 30-day period	5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Dry Lime FGD	not given	0.10 0.09	lb/MMBTU lb/MMBTU	24-hour Block avg. 30-day Rolling avg.	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	Wet Limstone FGD	not given	0.10 0.09	lb/MMBTU lb/MMBTU	24-hour Block avg. 30-day Rolling avg.	10/15/2004

Notes:

TABLE E-8
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for NO_x
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	SCR, Low NOx Burners, and Overfire Air	not given	0.1	lb/MBtu	1-hour	12/08/2005 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	SCR and Low NOx Burners	not given	0.07	lb/MBtu	30-day Rolling	7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	SCR and Low NOx Burners	not given	0.08	lb/MBtu	30-day Rolling	7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	SCR, Low NOx Burners, and Overfire Air	not given	0.067	lb/MBtu	24-hour rolling	5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	SCR and Low NOx Burners	not given	0.07	lb/MBtu	30-day Rolling	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	SCR and Low NOx Burners	not given	0.07	lb/MBtu	24-hour	10/15/2004

Notes:

TABLE E-9
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for H_2SO_4
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Dry Flue Gas Desulfurization System	not given	0.0064	lb/MMBTU		12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Dry Lime FGD	not given	No Limit			7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Dry Lime FGD	not given	0.0042	lb/MMBtu		7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Dry Spray Scrubber and Fabric Filter	not given	2.06	lbs/hr		5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Dry Lime FGD	not given	0.005	lb/MMBTU	24-hour	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	Wet Limestone FGD	not given	0.0044	lb/MMBTU	24-hour Block avg	10/15/2004

Notes:

TABLE E-10
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for Beryllium
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit	Averaging Period	Permit Date and Permit No.

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:
- RBLC Determinations added during or after January 1995
- SIC Code: 4911
- Process Type Code: 11.110 - Coal Combustion

The State
of Wyoming

Dave Freudenthal, Governor

Department of Environmental Quality

Herschler Building • 122 West 25th Street • Cheyenne, Wyoming 82002

ADMIN/OUTREACH	ABANDONED MINES	AIR QUALITY	INDUSTRIAL SITING	LAND QUALITY	SOLID & HAZ. WASTE	WATER QUALITY
(307) 777-7758	(307) 777-6145	(307) 777-7391	(307) 777-7368	(307) 777-7756	(307) 777-7752	(307) 777-7781
FAX 777-3610	FAX 777-6462	FAX 777-5616	FAX 777-6937	FAX 777-5864	FAX 777-5973	FAX 777-5973

May 17, 2004

Mr. Fred Carl
Director Environmental Services
Black Hills Corporation
P.O. Box 1400
Rapid City, SD 57709

Re: Air Quality Permit CT-3030 Extension

Dear Mr. Carl:

The Division is in receipt of your letter dated March 25, 2004, requesting to extend the construction period for Air Quality Permit CT-3030. Permit CT-3030, issued September 25, 2002, authorized the construction of a 500 megawatt (MW) pulverized coal fired electric generating facility, known as WYGEN 2, located at 13151 Hwy 51 approximately five (5) miles east of Gillette in Campbell County, Wyoming.

Condition 6 of the issued permit states that construction shall commence within 24 months of issuance of the permit. The allotted 24 months for construction is scheduled to lapse on September 25, 2004. An appeal of the final permit was filed on November 25, 2002 and action on the appeal is pending. For this reason, the Division will extend the permit for a period of one year. Construction must commence prior to September 25, 2005, for the approval to construct the WYGEN 2 Electric Generating Plant to remain valid.

If you should have any questions concerning this matter, please contact this office at (307) 777-7391.

Sincerely,

Dan Olson
Administrator
Air Quality Division

cc: Bob Gill
Mike Warren
Main File CT-3030

Joro Walker, USB #6676
David Becker USB #11037
WESTERN RESOURCE ADVOCATES
425 East 100 South Street
Salt Lake City, Utah 84111
Telephone: 801.487.9911
Fax: 801.486.4233
Attorneys for Utah Chapter of the Sierra Club

BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – the Sevier	:	
Power Company 270 MW Coal-Fired	:	MOTION FOR SUMMARY
Power Plant, Sevier County	:	JUDGMENT AND
Project Code: N2529-001	:	MEMORANDUM IN SUPPORT
DAQE-AN2529001-04	:	OF MOTION

The Utah Chapter of the Sierra Club (Sierra Club) respectfully moves for Summary Judgment on the claim in Statement of Reasons # 10 of its First Amended Request for Agency Action,[1] and for an order by the Air Quality Board (Board) remanding the Approval Order (AO) for the proposed plant to the Division of Air Quality and the Executive Secretary (collectively "DAQ") for further proceedings. In support of its motion, Sierra Club submits the following memorandum, together with the attached exhibits.

[1] Sierra Club submitted a motion to amend its request for agency action on February 16, 2007 after the production of the administrative record. Because the stipulated schedule approved by the Board requires that the first round of dispositive motions be filed by February 26, 2007, Sierra Club submits this motion for summary judgment in anticipation that the Board will grant the motion to amend the request for agency action.

Introduction

The Sierra Club moves for summary judgment on one claim, which requires an immediate remand of the AO to the DAQ for further proceedings. As specified in Statement of Reasons # 10, the Board must remand the AO because, under the applicable regulations, the AO is now invalid because more than 18 months have passed since DAQ issued the AO without Sevier Power Company (SPC) beginning construction on the project. Sierra Club respectfully requests that the Board grant summary judgment on this claim and remand the AO to DAQ to re-initiate the approval process.

Legal Standards

Summary Judgment

The Utah Administrative Procedures Act allows the Board to decide issues in this administrative appeal on a motion for summary judgment if the moving party meets the requirements of Rule 56 of the Utah Rules of Civil Procedure.[2] Under Rule 56(c), summary judgment is appropriate only "if the pleadings, depositions, answers to interrogatories, and admissions on file, together with the affidavits, if any, show that there is no genuine issue as to any material fact and that the moving party is entitled to a judgment as a matter of law."[3] Because summary judgment will cut off any discovery and the presentation of expert testimony, the Board must "examine all of the facts presented and the inferences to be drawn therefrom in the light most favorable to the nonmoving party."[4] The first question the Board must answer is whether there are any disputed issues of fact regarding the claim or claims on which a party is moving for

[2] Utah Code Ann. § 63-46b-1(4)(b).
[3] Utah R. Civ. P. 56(c).
[4] Grynberg v. Questar Pipeline Company, 2003 UT 8, ¶ 20, 70 P.3d 1 (2003).

judgment. If there are no disputed factual issues, the Board must then decide – based on the undisputed facts – whether the party that filed the motion should get judgment as a matter of law.

The purpose of a summary judgment motion is not "to judge the credibility of the averments of the parties, or witnesses, or the weight of the evidence,"[5] but rather the purpose is to avoid a trial on an issue when, even viewing the facts in the light most favorable to the non-moving party, the non-moving party cannot prevail.[6] The Sierra Club submits this motion for summary judgment based on the pleadings in this matter, the Administrative Record, and the exhibits attached to this memorandum. Because the facts related to Sierra Club's motion are undisputed in the record, the Board can address the second summary judgment question: whether the Sierra Club is entitled to judgment as a matter of law. Based on the applicable regulations and the provisions of the AO itself, the Sierra Club is entitled to judgment as a matter of law on the claim in Statement of Reasons # 10 that the AO has expired by operation of law.

Standard for Review of Legal Issues and DAQ's Decisions

Under the Utah Administrative Procedures Act (UAPA), the Board makes findings of fact and conclusions of law regarding the issues raised in a request for agency action.[7] As the Utah Supreme Court has noted, the Board is "vested with adjudicative

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[5] W.M. Barnes Co. v. Sohio Natural Res. Co., 627 P.2d 56, 59 (Utah 1981) (citation omitted).
[6] Draper City v. Estate of Bernardo, 888 P.2d 1097, 1101 (Utah 1995).
[7] Utah Code Ann. § 63-46b-10(1)(a)-(d) ("… the presiding officer shall sign and issue an order that includes: (a) a statement of the presiding officer's findings of fact based exclusively on the evidence of record in the adjudicative proceedings or on facts officially noted; (b) a statement of the presiding officer's conclusions of law; (c) a statement of the reasons for the presiding officer's decision; (d) a statement of any relief ordered by the agency").

functions,"[8] and sits in the same position with respect to the DAQ as a reviewing court sits with respect to a final action by an agency. The adjudicative nature of this proceeding requires the Board to apply the review provisions listed in the UAPA when reviewing DAQ decisions: the Board should grant relief if "it determines that a person seeking judicial review has been substantially prejudiced by" any of twelve deficiencies in the action the Board is reviewing.[9] Under the UAPA, a party is substantially prejudiced if "the agency has erroneously interpreted or applied the law," or if "the agency has engaged in an unlawful procedure or decision-making process, or has failed to follow prescribed procedures," or if "the agency action is based upon a determination of fact, made or implied by the agency, that is not supported by substantial evidence," or if "the agency action is … contrary to a rule of the agency … contrary to the agency's prior

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[8] Utah Chapter of the Sierra Club v. Air Quality Bd., 2006 UT 74, ¶ 12, 148 P.3d 960.

[9] Utah Code Ann. § 63-46b-16(4). This section provides, in full, that

(4) The appellate court shall grant relief only if, on the basis of the agency's record, it determines that a person seeking judicial review has been substantially prejudiced by any of the following:

(a) the agency action, or the statute or rule on which the agency action is based, is unconstitutional on its face or as applied;

(b) the agency has acted beyond the jurisdiction conferred by any statute;

(c) the agency has not decided all of the issues requiring resolution;

(d) the agency has erroneously interpreted or applied the law;

(e) the agency has engaged in an unlawful procedure or decision-making process, or has failed to follow prescribed procedure;

(f) the persons taking the agency action were illegally constituted as a decision-making body or were subject to disqualification;

(g) the agency action is based upon a determination of fact, made or implied by the agency, that is not supported by substantial evidence when viewed in light of the whole record before the court;

(h) the agency action is:

(i) an abuse of the discretion delegated to the agency by statute;

(ii) contrary to a rule of the agency;

(iii) contrary to the agency's prior practice, unless the agency justifies the inconsistency by giving facts and reasons that demonstrate a fair and rational basis for the inconsistency; or

(iv) otherwise arbitrary or capricious.

practice, unless the agency justifies the inconsistency by giving facts and reasons that demonstrate a fair and rational basis for the inconsistency; or …otherwise arbitrary or capricious."[10]

Under the Utah Air Conservation Act, the Board has the power to "hold hearings relating to any aspect of or matter in the administration of this chapter" and "issue orders necessary to enforce the provisions of this chapter."[11] By contrast, the power conferred by the Legislature on the Executive Secretary is subject to the Board's superior authority: "as authorized by the board subject to the provisions of this chapter, [the Executive Secretary may] enforce rules through the issuance of orders, including: … (ii) requiring the construction of new control facilities or any parts of new control facilities or the modification, extension, or alteration of existing control facilities or any parts of new control facilities."[12] Because the Utah Air Conservation Act specifies that the Board has the ultimate decision-making power within the Division of Air Quality, the Board must review the Executive Secretary's decisions without deference, and the Board is required under the UAPA make its own, independent findings of fact and conclusions of law regarding the issues raised in a request for agency action.[13]

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[10] Utah Code Ann. §§ 63-46b-16(4)(d), (e), (g), (h).
[11] Utah Code Ann. § 19-2-104(3)(a)-(b).
[12] Utah Code Ann. § 19-2-107(2)(g)(2).
[13] Utah Code Ann. § 63-46b-10(1)(a)-(d) ("… the presiding officer shall sign and issue an order that includes: (a) a statement of the presiding officer's findings of fact based exclusively on the evidence of record in the adjudicative proceedings or on facts officially noted; (b) a statement of the presiding officer's conclusions of law; (c) a statement of the reasons for the presiding officer's decision; (d) a statement of any relief ordered by the agency").

Statement of Undisputed Material Facts

1. On October 12, 2004, Richard W. Sprott, Executive Secretary of the Utah Air Quality Board, signed an AO authorizing construction and operation of the proposed Sevier Power Company 270 MW circulating fluidized bed (CFB) coal-fired power plant (DAQE-AN2529001-04) (Project Code: N2529-001). Exhibit 1 (Approval Order) at Cover Letter, AR SPC 2531.[14]

2. Condition No. 9 of the AO provided that "If construction and/or installation has not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11." Exhibit 1 at 5, AR SPC 2535.

3. Eighteen months after the date of the AO – on or about April 12, 2005 – SPC did not submit the required notification of the status of construction. See Exhibit 2 (Final Preliminary Index to the Administrative Record).

4. Eighteen months after the date of the AO – on or about April 12, 2006 – the Executive Secretary made no determination regarding a revocation of the AO, nor whether an extension of the AO was justified. See Exhibit 2 (Final Preliminary Index to the Administrative Record).

Argument

[14] Citations to the "AR" are to the Administrative Record in this matter. In addition to selections from the Administrative Record attached as exhibits to this motion, Sierra Club will provide copies of the cited documents to the Board upon request.

1. The Approval Order for SPC's Proposed Plant is Invalid and the Board Must Remand the AO to DAQ Because 18 Months Have Passed Since Approval Without Commencement of Construction and Without Reevaluation and Extension by the Executive Secretary (Statement of Reasons # 10)

The AO for the proposed SPC power plant must be remanded to the DAQ because the AO is no longer valid under Utah and federal regulations and by the terms of the AO itself. The applicable regulations provide that an AO to construct a source "shall become invalid if construction if not commenced within 18 months after receipt of such approval."[15] This federal regulation has been in effect since at least 1975,[16] and is incorporated into the Utah air quality regulations by Utah Administrative Code R307-405-19(1).[17]

Although the regulation also provides that the agency "may extend the 18-month period upon a satisfactory showing that an extension is justified,"[18] the Administrative Record in this matter shows that, after 18 months – on or about April 12, 2006 – SPC did not offer any showing that an extension was justified, nor did the Executive Secretary extend the 18-month period before that period ended.[19] Nowhere in the Administrative

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[15] 40 C.F.R. § 52.21(r)(2); Utah Admin. Code R307-405-19(1).

[16] See Grand Canyon Trust v. Tucson Elec. Power Co., 391 F.3d 979, 982 n.1 (9th Cir. 2004).

[17] This regulation, listed under "Source Obligations" in the Prevention of Significant Deterioration regulations, provides that "the provisions of 40 C.F.R. 52.21(r), effective March 3, 2003, are hereby incorporated by reference." Utah Admin. Code R307-405-19(1). The permittee is also bound by these regulations by the provisions in the AO itself, which provides that "[t]his AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including R307." Exhibit 1 at 12, AR SPC 2542.

[18] 40 C.F.R. § 52.21(r)(2), incorporated by reference in Utah Admin. Code R307-405-19(1).

[19] See Exhibit 2 (Final Preliminary Index to the Administrative Record). The Administrative Record contains no documents dated after October 12, 2004. Id. at 4. April 12, 2006 – 18 months after the date of the AO – falls well beyond the date of that last document.

Record does it show that construction has begun on the proposed power plant.[20] Indeed, although Condition 9 of the AO specifically provides that "[i]f construction and/or installation has not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation," the Administrative Record shows that SPC did not provide the required notification.[21]

Two federal courts that have considered the federal regulation incorporated in R307-405-19(1) have concluded that a permit "automatically expires" when 18 months pass from the approval of the permit without commencement of construction.[22] Specifically, the Ninth Circuit Court of Appeals found that

> a permit automatically becomes invalid in the enumerated circumstances unless the administrator exercises discretionary authority to extend the permit. On a natural reading of the language, administrative action is only required to forestall invalidation of a permit. No agency action is required to invalidate a permit if construction is not timely commenced.[23]

It is undisputed that the Executive Secretary did not extend the permit within the 18-month period required under the regulations. This automatic expiration is significant, because – notwithstanding there has been no stay of the AO since October 12, 2004 – it means that the AO to construct the proposed plant is now invalid, and has been since April 12, 2006. Any application to construct the proposed plant must be presented to the DAQ for consideration under current circumstances, subject to today's laws and

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[20] See id.
[21] Exhibit 1 at 5, AR SPC 2535; see Exhibit 2 (Final Preliminary Index to the Administrative Record).
[22] Grand Canyon Trust, 391 F.3d at 981 & 982 n.1; Roosevelt Campobello Int'l Park Comm'n v. EPA, 684 F.2d 1034, 1037 (1st Cir. 1982).
[23] Grand Canyon Trust, 391 F.3d at 981.

regulations.[24] Because the AO is now invalid, SPC must submit an updated Notice of Intent to DAQ and re-initiate the AO process to obtain approval to construct its proposed plant. Because the AO is invalid, the Board must remand this matter to DAQ and require SPC to re-submit the Notice of Intent, with whatever modifications SPC considers warranted by current factual and legal circumstances.

Furthermore, remand to the DAQ is necessary for re-consideration of the terms and conditions of the AO because the Executive Secretary did not make a determination, after 18 months, of whether changed circumstances required him to revoke the AO at that time. The AO and the DAQ regulations both provide expressly for Executive Secretary review 18 months after the AO is issued.[25] The 18-month review is mandatory under the regulations: "[a]pproval orders issued by the executive secretary in accordance with the provisions of R307-401 shall be reviewed eighteen months after the date of issuance to determine the status of construction …. If a continuous program of construction … is not proceeding, the executive secretary may revoke the approval order."[26]

The Administrative Record reflects that SPC did not notify the Executive Secretary of the status of the project as required under the terms of the permit, and that the Executive Secretary did not conduct the review required by regulation in April 2006.[27] This absence of this mandatory review prevented the Executive Secretary from

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[24] See Roosevelt Campobello, 684 F.2d at 1039.
[25] Exhibit 1 at 5, AR SPC 2535 ("If construction and/or installation has not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11."); see also Utah Admin. Code R307-401-18 (formerly R307-401-11).
[26] Utah Admin. Code R307-401-18 (emphasis added).
[27] See Exhibit 2 (Final Preliminary Index to the Administrative Record).

assessing whether any changed circumstances warranted revocation of the AO after the eighteen months during which construction had not begun. Because the AO automatically expired in April 2006, and because the Executive Secretary failed to conduct the mandatory 18-month review required under the regulations and permit conditions, the Board must grant summary judgment on the claim in Statement of Reasons # 10 and remand this matter to the DAQ for SPC to submit a revised Notice of Intent to DAQ, based on current circumstances and conditions, to obtain approval to construct the proposed plant.

Dated: February 26, 2007

___/s/_____
JORO WALKER
DAVID BECKER
Attorneys for Utah Chapter of the Sierra Club

CERTIFICATE OF SERVICE

I hereby certify that on this 26th day of February 2007, I caused a copy of the foregoing Motion for Summary Judgment and Memorandum in Support of Motion to be emailed to the following:

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__/s/_____
DAVID BECKER
Attorney for Sierra Club

EXHIBIT 1

State of Utah

Department of
Environmental Quality

Dianne R. Nielson, Ph.D.
Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

OLENE S. WALKER
Governor

GAYLE F. McKEACHNIE
Lieutenant Governor

FILE COPY

DAQE-AN2529001-04

October 12, 2004

Clark M. Mower
NEVCO Energy Company, LLC
620 South Main Street
Bountiful, Utah 84010

Dear Mr. Mower:

Re: Approval Order: Sevier Power Company's 270 MW Coal-Fired Power Plant, Sevier County – CDS A; ATT: PSD: NSPS, MACT, HAPs, TITLE IV MAJOR, TITLE V MAJOR
Project Code: N2529-001

The attached document is the Approval Order (AO) for the above-referenced project.

Future correspondence on this Approval Order should include the engineer's name as well as the DAQE number as shown on the upper right-hand corner of this letter. Please direct any technical questions you may have on this project to Mr. John D. Jenks. He may be reached at (801) 536-4459.

Sincerely,

Richard W. Sprott, Executive Secretary
Utah Air Quality Board

RWS:JJ:re

cc: Central Utah Public Health Department
Mike Owens, EPA Region VIII

SPC 2531

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

APPROVAL ORDER: SEVIER POWER COMPANY'S 270 MW COAL-FIRED POWER PLANT

Prepared By: John D. Jenks, Engineer
(801) 536-4459
Email: jjenks@utah.gov

APPROVAL ORDER NUMBER

DAQE-AN2529001-04

Date: October 12, 2004

Sevier Power Company
Source Contact
Clark M. Mower
(801) 298-7333

Richard W. Sprott
Executive Secretary
Utah Air Quality Board

Fluidized bed heat exchangers
Natural gas startup burners
Air-cooled condenser**
Stack (at least 460 feet in height as measured from base of stack)

F. Control Equipment
Induced draft baghouses and cartridge-type particulate filters at all material transfer points
Silo baghouses
Ash recycle cyclones**
Dry-lime scrubber
Selective non-catalytic reduction (using)
Ammonia injection system with ammonia storage tank
Primary stack baghouse with bag leak detectors

G. Steam System**
Water treatment**
Turbine generator**
Air heater**

H. Associated Equipment
Diesel-fired emergency fire pump
Diesel-fired emergency generator
Diesel storage tanks
Paved haul roads

* Equivalency shall be determined by the Executive Secretary.

** This equipment is listed for informational purposes only. There are no emissions from this equipment.

8. A manometer or magnehelic pressure gauge shall be installed to measure the differential pressure across the main stack fabric filter (baghouse). Static pressure differential across the fabric filter shall be between 0.5 to 12 inches of water column. The pressure gauge shall be located such that an inspector /operator can safely read the indicator at any time. The reading shall be accurate to within plus or minus 1.0 inches water column. The instrument shall be calibrated according to the manufactures instructions at least once every 12 months. Continuous or intermittent recording of the reading is not required.

9. SPC shall notify the Executive Secretary in writing when the installation of the equipment listed in Condition #7 has been completed and is operational, as an initial compliance inspection is required. To insure proper credit when notifying the Executive Secretary, send your correspondence to the Executive Secretary, attn: Compliance Section.

If construction and/or installation has not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11.

Monitoring - Continuous Emissions Monitoring

23. SPC shall install, calibrate, maintain, and operate a continuous emissions monitoring system on the main boiler stack. SPC shall record the output of the system, for measuring the SO_2 emissions, the NO_x emissions and the CO emissions. The monitoring system shall comply with all applicable sections of R307-170; 40 CFR 60.13; and 40 CFR 60, Appendix B.

    All continuous emissions monitoring devices as required in federal regulations and state rules shall be installed and operational prior to placing the affected source in operation.

    Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of an affected source shall continuously operate all required continuous monitoring systems and shall meet minimum frequency of operation requirements as outlined in 40 CFR 60.13 and Section R307-170.

Records & Miscellaneous

24. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this Approval Order including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Executive Secretary which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded.

25. The owner/operator shall comply with R307-150 Series. Inventories, Testing and Monitoring.

26. The owner/operator shall comply with R307-107. General Requirements: Unavoidable Breakdowns.

The Executive Secretary shall be notified in writing if the company is sold or changes its name.

Under R307-150-1, the Executive Secretary may require a source to submit an emission inventory for any full or partial year on reasonable notice.

This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including R307.

A copy of the rules, regulations and/or attachments addressed in this AO may be obtained by contacting the Division of Air Quality. The Utah Administrative Code R307 rules used by DAQ, the Notice of Intent (NOI) guide, and other air quality documents and forms may also be obtained on the Internet at the following web site:
http://www.airquality.utah.gov/

EXHIBIT 2

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Counsel for the Executive Secretary,
Air Quality Board of Utah

BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order - the Sevier Power Company 270 MW Coal-Fired Power Plant, Sevier County Project Code: N2529-001 DAQE-AN2529001-04	EXECUTIVE SECRETARY'S IDENTIFICATION OF THE ADMINISTRATIVE RECORD

The Executive Secretary has identified the documents in the attached index as the Executive Secretary's Administrative Record in the above-captioned matter as of October 12, 2004, the date of the issuance of the Approval Order. As of today's date, the documents are available to all parties for inspection and copying at the Department of Environmental Quality, Division of Air Quality, 150 North 1950 West, Bldg #1, Salt Lake City, Utah.

Dated this 6TH day of FEBRUARY, 2007.

Paul M. McConkie
Christian C. Stephens
Assistant Attorneys General, for
the Executive Secretary

In the Matter of:

AGENCY ADMINISTRATIVE RECORD

Abbreviations used:

- DAQ is the Division of Air Quality

Record Description	Date	Added to Record By	Record page (SPC)
Cover letters to U.S. Forest Service and Bureau of Land Management regarding submittal of Notice of Intent	04/22/03 05/02/03	DAQ	0001-0003
Letter to John Jenks (DAQ) from Meteorological Solutions Inc. in response to 11/05/03 telephone conversation requesting additional information	12/05/03	DAQ	0004-0022
Letter to Rusty Ruby (DAQ) from Meteorological Solutions Inc. enclosing revised Prevention of Significant Deterioration Permit Application for Sevier Power Company Proposed 270 MW Coal-Fired Power Plant, Volumes 1 and 2	09/10/03	DAQ	0023-0027
Letter to Tom Orth (DAQ) from Meteorological Solutions Inc. in response to (DAQ) letter DAQP-059-03 dated May 29, 2003	07/02/03	DAQ	0028-0051
Notice of Intent Volume 1 Prevention of Significant Deterioration Permit Application for Sevier Power Company Proposed 270 MW Coal-Fired Power Plant submitted by Meteorological Solutions Inc. on behalf of Sevier Power Company	09/10/03	DAQ	0052-0368
Notice of Intent Volume 2 Appendices Prevention of Significant Deterioration Permit Application for Sevier Power Company Proposed 270 MW Coal-Fired Power Plant submitted by Meteorological Solutions Inc. on behalf of Sevier Power Company	09/10/03	DAQ	0369-0738
E-Mail Correspondence	04/22/03 through 10/01/04	DAQ	0739-0976

Record Description	Date	Added to Record By	Record page (SPC)
Letter to Rick Sprott, Director, (DAQ) from John Bunyak, Chief, Policy, Planning and Permit Review Branch, U.S. Department of the Interior, National Park Service enclosing public comments	04/12/04	DAQ	0977-0989
E-mails between John Jenks (DAQ) and Don Shepherd, National Park Service Air Resources Division re NEVCO-Sevier	11/04/03 through 11/17/03	DAQ	0990-0991
Memorandum from Don Shepherd to John Notar re NEVCO Energy–Sevier Power–Engineering Analysis	11/04/03	DAQ	0992-0995
Memorandum to Permitting and Planning Branches from Richard W. Sprott re Utah Division of Air Quality (UDAQ) Class I Significant Impact Levels	12/16/03	DAQ	0995a-0995b
(DAQ) New Source Plan Review (Engineering)	12/23/03	DAQ	0996-1070
Modeling Memorandum to file from Tom Orth, Air Quality Modeler, (DAQ) re Particulate Matter Less Than 10 Microns (PM_{10}) Background Concentrations for the Nevco Energy, Sevier Power Plant (Nevco), Prevention of Significant Deterioration (PSD) Air Quality Impact Analysis (AQIA), in Sigurd, Utah	03/26/03	DAQ	1071-1072
Memorandum from Cheryl Heying, Planning Branch Manager, (DAQ) to John Jenks, NSR Engineer re Modeling Analysis Review for the NEVCO Energy - Sevier Power Plant, Sigard, Utah	12/24/03	DAQ	1073-1085
Letter to Clark M. Mower, NEVCO Energy Company, LLC from Rusty Ruby, Manager, New Source Review Section (DAQ) re Intent to Approve: Sevier Power Company's 270 MW Coal-Fired Power Plant, Sevier County - CDS A; ATT: PSD: NSPS, MACT, HAP's, TITLE IV MAJOR, TITLE V MAJOR Project Code: N2529-001	02/27/04	DAQ	1086-1098
Memorandum to Permitting and Planning Branches from Richard W. Sprott, Director, re Significant Impact Levels for the National Ambient Air Quality Standards and Prevention of Significant Deterioration Class II Analyses	02/27/04	DAQ	1098a-1098b

Record Description	Date	Added to Record By	Record page (SPC)
Various Public Notices	10/15/03 through 06/02/04	DAQ	1099-1114
Transcript of Public Hearing	03/18/04	DAQ	1115-1125
Letter to Rick Sprott, Director (DAQ) from U.S. Environmental Protection Agency re Comments on Intent-to-Approve for NEVCO Energy's Sevier Power Company Project	04/06/04	DAQ	1126-1130
Public Comments	various	DAQ	1131-2493
Memorandum to file from John D. Jenks, Environmental Engineer, (DAQ) through Rusty Ruby, (DAQ) re Response to Comments received on Sevier Power Company (N2529-001)	09/27/04	DAQ	2494-2530
Letter to Clark M. Mower, NEVCO Energy Company, LLC from Richard W. Sprott, Executive Secretary, (DAQ) re **Approval Order**: Sevier Power Company's 270 MW Coal-Fired Power Plant, Sevier County - CDS A; ATT: PSD: NSPS, MACT, HAP's, TITLE IV MAJOR, TITLE V MAJOR Project Code: N2529-001	10/12/04	DAQ	2531-2543

CERTIFICATE OF SERVICE

I hereby certify that on this 6TH day of FEBRUARY, 2007, I caused a copy of the foregoing Executive Secretary's Identification of the Administrative Record (SPC) to be emailed or mailed by United States Mail, postage prepaid, to the following:

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Attorneys for Utah Chapter of the Sierra Club

BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station, Millard County, Utah Project Code: N0327-010 DAQE-AN0327010-04	:	MOTION FOR SUMMARY JUDGMENT AND MEMORANDUM IN SUPPORT OF MOTION

The Utah Chapter of the Sierra Club (Sierra Club) respectfully moves for Summary Judgment on the claims in Statements of Reasons # 20, 21, and 22 of its Second Amended Request for Agency Action,[1] and for an order by the Air Quality Board (Board) remanding the Approval Order (AO) for Unit 3 to the Division of Air Quality and the Executive Secretary (collectively "DAQ") for further proceedings. In support of its motion, Sierra Club submits the following memorandum, together with the attached exhibits and affidavits.

[1] Sierra Club submitted a motion to amend its request for agency action on February 16, 2007 after the production of the administrative record. Because the stipulated schedule approved by the Board requires that the first round of dispositive motions be filed by February 26, 2007, Sierra Club submits this motion for summary judgment in anticipation that the Board will grant the motion to amend the request for agency action.

Introduction

The Sierra Club moves for summary judgment on three claims, which require an immediate remand of the Unit 3 AO to the DAQ for further proceedings. As specified in Statement of Reasons # 22, the Board must remand the AO because, under the applicable regulations, the AO is now invalid because more than 18 months have passed since DAQ issued the AO without construction beginning on the project. In addition, after the Unit 3 AO expired by operation of law, DAQ issued a decision in August 2006 approving a modification to the AO to change the approved boiler technology from subcritical to supercritical, without following the process required by the Utah air quality regulations and the terms of the permit itself, and without notice to the public of the proposed changes and an opportunity to comment as required by the regulations. DAQ's decision to accept the proposed change to a supercritical boiler was arbitrary and capricious, and contrary to law, and the Board must remand the AO to the DAQ for further analysis of, and public comment on, the proposed change. Sierra Club respectfully requests that the Board grant summary judgment on these claims and remand the AO to DAQ for further proceedings.

Legal Standards

Summary Judgment

The Utah Administrative Procedures Act allows the Board to decide issues in this administrative appeal on a motion for summary judgment if the moving party meets the requirements of Rule 56 of the Utah Rules of Civil Procedure.[2] Under Rule 56(c), summary judgment is appropriate only "if the pleadings, depositions, answers to

[2] Utah Code Ann. § 63-46b-1(4)(b).

interrogatories, and admissions on file, together with the affidavits, if any, show that there is no genuine issue as to any material fact and that the moving party is entitled to a judgment as a matter of law."[3] Because summary judgment will cut off any discovery and presentation of expert testimony, the Board must "examine all of the facts presented and the inferences to be drawn therefrom in the light most favorable to the nonmoving party."[4] The first question the Board must answer is whether there are any disputed issues of fact regarding the claim or claims on which a party is moving for judgment. If there are no disputed factual issues, the Board must then decide – based on the undisputed facts – whether the party that filed the motion should get judgment as a matter of law.

The purpose of a summary judgment motion is not "to judge the credibility of the averments of the parties, or witnesses, or the weight of the evidence,"[5] but rather the purpose is to avoid a trial on an issue when, even viewing the facts in the light most favorable to the non-moving party, the non-moving party cannot prevail.[6] The Sierra Club submits this motion for summary judgment based on the pleadings in this matter, the Administrative Record, and the exhibits and affidavits attached to this memorandum. Because the facts related to Sierra Club's motion are undisputed in the record, the Board can address the second summary judgment question: whether the Sierra Club is entitled to judgment as a matter of law. Based on the applicable regulations and the provisions of the AO itself, the Sierra Club is entitled to judgment as a matter of law on the claims in

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[3] Utah R. Civ. P. 56(c).
[4] Grynberg v. Questar Pipeline Company, 2003 UT 8, ¶ 20, 70 P.3d 1 (2003).
[5] W.M. Barnes Co. v. Sohio Natural Res. Co., 627 P.2d 56, 59 (Utah 1981) (citation omitted).
[6] Draper City v. Estate of Bernardo, 888 P.2d 1097, 1101 (Utah 1995).

Statement of Reasons # 20, # 21, and # 22 that the AO has expired and that DAQ's decision in August 2006 to approve a change to a supercritical boiler, without changing the terms and conditions of the AO and without allowing public notice and comment, was arbitrary and capricious, and contrary to the law, regulations, and required procedures.

Standard for Review of Legal Issues and DAQ's Decisions

Under the Utah Administrative Procedures Act (UAPA), the Board makes findings of fact and conclusions of law regarding the issues raised in a request for agency action.[7] As the Utah Supreme Court has noted, the Board is "vested with adjudicative functions,"[8] and sits in the same position with respect to the DAQ as a reviewing court sits with respect to a final action by an agency. The adjudicative nature of this proceeding requires the Board to apply the review provisions listed in the UAPA when reviewing DAQ decisions: the Board should grant relief if "it determines that a person seeking judicial review has been substantially prejudiced by" any of twelve deficiencies in the action the Board is reviewing.[9] Under the UAPA, a party is substantially

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[7] Utah Code Ann. § 63-46b-10(1)(a)-(d) ("… the presiding officer shall sign and issue an order that includes: (a) a statement of the presiding officer's findings of fact based exclusively on the evidence of record in the adjudicative proceedings or on facts officially noted; (b) a statement of the presiding officer's conclusions of law; (c) a statement of the reasons for the presiding officer's decision; (d) a statement of any relief ordered by the agency").

[8] Utah Chapter of the Sierra Club v. Air Quality Bd., 2006 UT 74, ¶ 12, 148 P.3d 960.

[9] Utah Code Ann. § 63-46b-16(4). This section provides, in full, that
(4) The appellate court shall grant relief only if, on the basis of the agency's record, it determines that a person seeking judicial review has been substantially prejudiced by any of the following:
(a) the agency action, or the statute or rule on which the agency action is based, is unconstitutional on its face or as applied;
(b) the agency has acted beyond the jurisdiction conferred by any statute;
(c) the agency has not decided all of the issues requiring resolution;
(d) the agency has erroneously interpreted or applied the law;

prejudiced if "the agency has erroneously interpreted or applied the law," or if "the agency has engaged in an unlawful procedure or decision-making process, or has failed to follow prescribed procedures," or if "the agency action is based upon a determination of fact, made or implied by the agency, that is not supported by substantial evidence," or if "the agency action is … contrary to a rule of the agency … contrary to the agency's prior practice, unless the agency justifies the inconsistency by giving facts and reasons that demonstrate a fair and rational basis for the inconsistency; or …otherwise arbitrary or capricious."[10]

Under the Utah Air Conservation Act, the Board has the power to "hold hearings relating to any aspect of or matter in the administration of this chapter" and "issue orders necessary to enforce the provisions of this chapter."[11] By contrast, the power conferred by the Legislature on the Executive Secretary is subject to the Board's superior authority: "as authorized by the board subject to the provisions of this chapter, [the Executive Secretary may] enforce rules through the issuance of orders, including: … (ii) requiring the construction of new control facilities or any parts of new control facilities or the

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(e) the agency has engaged in an unlawful procedure or decision-making process, or has failed to follow prescribed procedure;
(f) the persons taking the agency action were illegally constituted as a decision-making body or were subject to disqualification;
(g) the agency action is based upon a determination of fact, made or implied by the agency, that is not supported by substantial evidence when viewed in light of the whole record before the court;
(h) the agency action is:
(i) an abuse of the discretion delegated to the agency by statute;
(ii) contrary to a rule of the agency;
(iii) contrary to the agency's prior practice, unless the agency justifies the inconsistency by giving facts and reasons that demonstrate a fair and rational basis for the inconsistency; or
(iv) otherwise arbitrary or capricious.

[10] Utah Code Ann. §§ 63-46b-16(4)(d), (e), (g), (h).

[11] Utah Code Ann. § 19-2-104(3)(a)-(b).

modification, extension, or alteration of existing control facilities or any parts of new control facilities."[12] Because the Utah Air Conservation Act specifies that the Board has the ultimate decision-making power within the Division of Air Quality, the Board must review the Executive Secretary's decisions without deference, and the Board is required under the UAPA make its own, independent findings of fact and conclusions of law regarding the issues raised in a request for agency action.[13]

Statement of Undisputed Material Facts

1. On October 15, 2004, Richard W. Sprott, Executive Secretary of the Utah Air Quality Board, signed the AO authorizing the construction and operation of an additional 950 MW coal-fired power plant unit at the Intermountain Power Plant in Millard County, Utah (DAQE-AN0327010-04)(Project Code: N0327-010). Exhibit 1 (Unit 3 Approval Order) at 1, AR IPSC 4331.[14]

Facts Related to Statement of Reasons # 22

2. Condition No. 8 of the AO provided that "If construction and/or installation has not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation

[12] Utah Code Ann. § 19-2-107(2)(g)(2).
[13] Utah Code Ann. § 63-46b-10(1)(a)-(d) ("… the presiding officer shall sign and issue an order that includes: (a) a statement of the presiding officer's findings of fact based exclusively on the evidence of record in the adjudicative proceedings or on facts officially noted; (b) a statement of the presiding officer's conclusions of law; (c) a statement of the reasons for the presiding officer's decision; (d) a statement of any relief ordered by the agency").
[14] Citations to the "AR" are to the Administrative Record in this matter. In addition to selections from the Administrative Record attached as exhibits to this motion, Sierra Club will provide copies of the cited documents to the Board upon request.

and may revoke the AO in accordance with R307-401-11." Exhibit 1 at 5, AR IPSC 4336.

3. Eighteen months after the date of the AO – on or about April 15, 2005 – IPSC did not submit the required notification of the status of construction. See Exhibit 2 (Final Preliminary Index to the Administrative Record).

4. Eighteen months after the date of the AO – on or about April 15, 2006 – the Executive Secretary made no determination regarding a revocation of the AO, nor whether an extension of the AO was justified. See Exhibit 2 (Final Preliminary Index to the Administrative Record).

Facts Related to Statements of Reasons # 20 & # 21

5. Condition 4 of the AO provided that "Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved in accordance with R307-401-1." Exhibit 1 at 3, AR IPSC 4334.

6. Condition 6 of the AO provided that "Intermountain Power Service Corporation (IPSC) shall install and operate the nominal 950 gross-MW power generating Unit 3 with dry-bottom pulverized coal fired boiler and modified equipment associated with Unit 3, as defined by this AO, in accordance with the terms and conditions of this AO, which was written pursuant to IPSC's Notice of Intent submitted to the Division of Air Quality (DAQ) on December 16, 2002 and significant additional information provided throughout the process." Exhibit 1 at 3, AR IPSC 4334.

7. Condition 7 of the AO provided that "The approved installations shall consist of the following equipment or equivalent* … * Equivalency shall be determined by the Executive Secretary." Exhibit 1 at 4-5, AR IPSC 4334-35.

8. In its August 24, 2004 Response to Comments on the Unit 3 Draft AO, IPSC answered Sierra Club's statement that DAQ and IPSC should have considered a supercritical pulverized coal (PC) boiler for Unit 3. IPSC asserted, among other statements, that :

- "an additional subcritical boiler [is] more appropriate [than a supercritical boiler] based on safety, environmental, and economic considerations."
- "Having two different operating cycles [for subcritical Units 1 and 2 and for a supercritical Unit 3] could pose problems with safe operation of the units if operators switch from one unit to the other."
- "If operators are dedicated to the new unit only, additional staff will be required."
- "With the low proposed emission limits for With the low proposed emission limits for SO_2, NO_X, and particulates [in the draft AO], the actual reduction in tons per year does not warrant the increase in capital costs, safety, and equipment compatibility issues associated with a supercritical boiler.
- "There are reliability concerns with supercritical in favor os subcritical boiler design."

Exhibit 3 (IPP Response to Public Comments Received by UDAQ on the Draft Approval Order IPP Unit 3), AR IPSC 3891.

9. In its October 14, 2004 Response to Comments on the Intent to Approve for IPSC Unit 3, DAQ also responded to Sierra Club's statement that DAQ and IPSC should have considered a supercritical PC boiler for Unit 3. The agency stated that: "a top-down analysis including supercritical boiler technology, though not required, was provided. That analysis shows that supercritical boilers would not be appropriate for the IPP project." Exhibit 4 (UDAQ Response to Comments

received on IPSC Intent to Approve number DAQE-IN327010-04), AR IPSC 4297.

10. On August 4, 2006, the Utah Associated Municipal Power Systems (hereafter referred to as "IPSC") made a request by letter to DAQ notifying the agency of the intent to change the technology for the proposed IPSC Unit 3 from a subcritical to a supercritical pulverized coal fired boiler. Exhibit 5 (Letter to Rick Sprott, DAQ, from Douglas O. Hunter re: Equivalency Determination), AR IPSC 4473-77.

11. In its August 4, 2006 letter, IPSC stated that "[i]nstallation of a supercritical boiler will result in a net decrease in emissions as measured in lbs/MWh." Exhibit 5 at 3, AR IPSC 4475.

12. In its August 4, 2006 letter, IPSC stated, in comparing subcritical and supercritical boiler technology, that "there is approximately a three percent improvement in heat rate between the two cycles, thereby increasing the power output" of the supercritical technology "for the same coal burned in the boiler." Exhibit 5 at 2, AR IPSC 4474.

13. On August 17, 2006, DAQ responded that if found "in accordance with Condition 7 of the Approval Order number DAQE-AN0327010-04, a supercritical PC boiler is equivalent to the permitted unit," thereby approving the modification IPSC requested. Exhibit 6 (Letter to Doug Hunter from Rick Sprott, DAQ, re: Equivalency Determination, August 17, 2006), AR IPSC 4478. DAQ did not approve any other changes to the AO. See id.

14. The Administrative Record contains no analysis to support the Executive Secretary's determination. See Exhibit 2 (Final Preliminary Index to the Administrative Record).

15. There was no notice to the public of the proposed modification of the AO, and no opportunity for public comment, before the Executive Secretary approved the modification of the AO. See Exhibit 2 (Final Preliminary Index to the Administrative Record).

Argument

1. The Approval Order for Unit 3 is Invalid and the Board Must Remand the AO to DAQ Because 18 Months Have Passed Since Approval Without Commencement of Construction and Without Reevaluation and Extension by the Executive Secretary (Statement of Reasons # 22)

The AO for Unit 3 must be remanded to the DAQ because the AO is no longer valid under Utah and federal regulations and by the terms of the AO itself. The applicable regulations provide that an AO to construct a source "shall become invalid if construction if not commenced within 18 months after receipt of such approval."[15] This federal regulation has been in effect since at least 1975,[16] and is incorporated into the Utah air quality regulations by Utah Administrative Code R307-405-19(1).[17]

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[15] 40 C.F.R. § 52.21(r)(2); Utah Admin. Code R307-405-19(1).

[16] See Grand Canyon Trust v. Tucson Elec. Power Co., 391 F.3d 979, 982 n.1 (9th Cir. 2004).

[17] This regulation, listed under "Source Obligations" in the Prevention of Significant Deterioration regulations, provides that "the provisions of 40 C.F.R. 52.21(r), effective March 3, 2003, are hereby incorporated by reference." Utah Admin. Code R307-405-19(1). The permittee is also bound by these regulations by the provisions in the AO itself, which provides that "[t]his AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including R307." Exhibit 1 at 13, AR IPSC 4344.

Although the regulation also provides that the agency "may extend the 18-month period upon a satisfactory showing that an extension is justified,"[18] the Administrative Record in this matter shows that, after 18 months – on or about April 15, 2006 – IPSC did not offer any showing that an extension was justified, nor did the Executive Secretary extend the 18-month period before that period ended.[19] Nowhere in the Administrative Record does it show that construction has begun on Unit 3.[20] Indeed, although Condition 8 of the AO specifically provides that "[i]f construction and/or installation has not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation," the Administrative Record shows that IPSC did not provide the required notification.[21]

Two federal courts that have considered the federal regulation incorporated in R307-405-19(1) have concluded that a permit "automatically expires" when 18 months pass from the approval of the permit without commencement of construction.[22] Specifically, the Ninth Circuit Court of Appeals found that

> a permit automatically becomes invalid in the enumerated circumstances unless the administrator exercises discretionary authority to extend the permit. On a natural reading of the language, administrative action is only required to forestall invalidation of a permit. No agency action is required to invalidate a permit if construction is not timely commenced.[23]

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[18] 40 C.F.R. § 52.21(r)(2), incorporated by reference in R307-405-19(1).
[19] See Exhibit 2 (Final Preliminary Index to the Administrative Record). The Administrative Record contains no documents dated between September 8, 2005 and August 4, 2006. Id. at 12. April 15, 2006 – 18 months after the date of the AO – falls within this empty date range.
[20] See id.
[21] Exhibit 1 at 5, AR 4336; see Exhibit 2 (Final Preliminary Index to the Administrative Record).
[22] Grand Canyon Trust, 391 F.3d at 981 & 982 n.1; Roosevelt Campobello Int'l Park Comm'n v. EPA, 684 F.2d 1034, 1037 (1st Cir. 1982).
[23] Grand Canyon Trust, 391 F.3d at 981.

It is undisputed that the Executive Secretary did not extend the permit within the 18-month period required under the regulations. This automatic expiration is significant, because – notwithstanding there has been no stay of the AO since October 15, 2004 – it means that the AO to construct Unit 3 is now invalid, and has been since April 15, 2006. Any application to construct Unit 3 must be presented to the DAQ for consideration under current circumstances, subject to today's laws and regulations.[24] Because the AO is now invalid, IPSC must submit an updated Notice of Intent to DAQ – presumably incorporating a supercritical boiler described in the August 4, 2006 AO modification request – and re-initiate the AO process to obtain approval to construct Unit 3. Because the AO is invalid, the Board must remand this matter to DAQ and require IPSC to re-submit the Notice of Intent, with whatever modifications IPSC considers warranted by its proposed change in boiler technology and by current factual and legal circumstances.

Furthermore, remand to the DAQ is necessary for re-consideration of the terms and conditions of the AO because the Executive Secretary did not make a determination, after 18 months, of whether changed circumstances required him to revoke the AO at that time. The AO and the DAQ regulations both provide expressly for Executive Secretary review 18 months after the AO is issued.[25] The 18-month review is mandatory under the regulations: "[a]pproval orders issued by the executive secretary in accordance with the provisions of R307-401 shall be reviewed eighteen months after the date of issuance to

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[24] See Roosevelt Campobello, 684 F.2d at 1039.

[25] Exhibit 1 at 5, AR at 4336 ("If construction and/or installation has not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11."); see also Utah Admin. Code R307-401-18 (formerly R307-401-11).

determine the status of construction …. If a continuous program of construction … is not proceeding, the executive secretary may revoke the approval order."[26]

The Administrative Record reflects that IPSC did not notify the Executive Secretary of the status of the project as required under the terms of the permit, and that the Executive Secretary did not conduct the review required by regulation in April 2006.[27] This absence of this mandatory review prevented the Executive Secretary from assessing whether any changed circumstances warranted revocation of the AO after the eighteen months during which construction had not begun. Because the AO automatically expired in April 2006, and because the Executive Secretary failed to conduct the mandatory 18-month review required under the regulations and permit conditions, the Board must remand this matter to the DAQ for IPSC to submit a revised Notice of Intent to DAQ, based on current circumstances and conditions, to obtain approval to construct Unit 3.

2. The Board Must Remand the Unit 3 Permit Decision Because DAQ's Approval of IPSC's Request to Modify the AO to Allow Installation of a Supercritical Boiler Was Arbitrary and Capricious and Unlawful (Statements of Reasons # 20 & # 21).

Despite the expiration of the AO by operation of law in April 2006, on August 4, 2006, almost two years after the Executive Secretary signed the AO authorizing the construction and operation of the Unit 3 950 megawatt coal-fired unit at the Intermountain Power Plant, IPSC requested that it be allowed to change the technology for the proposed unit from a subcritical to a supercritical pulverized coal (PC) fired boiler. Exhibit 5, AR at 4473-77. On August 17, 2006, DAQ responded that, "in

[26] Utah Admin. Code R307-401-18 (emphasis added).
[27] See Exhibit 2 (Final Preliminary Index to the Administrative Record).

accordance with Condition 7" of the AO, a supercritical PC boiler is "equivalent" to the permitted subcritical unit, thereby approving the project changes. Exhibit 6, AR IPSC 4478. If the Board were to determine that the expiration of the AO alone does not justify remand to the DAQ, the Board must nevertheless remand the AO to DAQ because DAQ's decision to approve this AO modification was unlawful.

Importantly, there is no "equivalency" determination in the record. See Exhibit 2 (Final Preliminary Index to the Administrative Record). As evidenced in the Administrative Record, DAQ undertook no independent analysis of IPSC's statements regarding comparisons between subcritical and supercritical technology at Unit 3. Id. Moreover, DAQ did not give the public either notice of or the opportunity to comment on the IPSC request, the company's statements, or any assumptions about "equivalency."[28] Id. Nor was the public permitted to submit evidence or argument prior to the Executive Secretary's decision, that a change in technology warranted a substantial reduction in emission limits in the AO. Id.

In approving the technology change, DAQ did not change any other terms and conditions of the AO to reflect the increase in efficiency that is achieved with supercritical technology. AR at 4478. Specifically, the agency did not reduce emission limits in any way to secure a benefit to public health, the environment or visibility from the improved technology. Id. Nor did the agency change the generating capacity for Unit 3 specified in the AO.

It is true, that in its Request for Agency Action, Sierra Club argued, and still argues, that a supercritical boiler would be superior to a subcritical boiler for Unit 3 in

[28] Because there is no DAQ analysis in the record, the public was prohibited from commenting on this analysis as well.

terms of gains to the public health, environment and visibility. Exhibit 7, AR IPSC 4496. This contention was based on the fact that a supercritical boiler for the 950 gross megawatt power plant would produce significantly lower emissions of criteria pollutants, as well as CO_2, and that, after proper BACT analysis,[29] the terms and conditions of the AO would reflect these lower emission rates. Id. However, as the AO now stands, after the August 17, 2006 amendment, a supercritical unit may be installed at Unit 3, with no attendant decrease in hourly emissions or other restrictions, such as on maximum heat input capacity or annual amount of coal burned, that would ultimately limit emissions. Exhibit 6, AR IPSC 4478. Instead, the amended AO allows IPSC to generate more electricity than specified by the AO terms and conditions and, as a result, to produce the same amount of air pollution.

IPSC itself states that there are "environmental benefits" from using a supercritical boiler. Exhibit 5, AR at 4473 ("[W]e have concluded that a supercritical boiler design is more efficient and better for the environment."). Because Sierra Club was unlawfully prevented from commenting on the technology change, and because the AO, as modified, does not reflect – through lower emissions limitations – what IPSC itself states are the environmental benefits of a supercritical boiler, Sierra Club respectfully asks the Board to reverse DAQ's decision to approve the technology change and remand the AO to the agency so that the decision can be made according to the law.

Specifically, as indicated below, DAQ's failure to provide for public notice and comment, as well as the decision to allow the technology change, is arbitrary and

[29] For purposes of this motion for summary judgment, Sierra Club is not arguing what BACT determination DAQ must make on remand. Rather, the undisputed facts in the record show that BACT must be different because DAQ's equivalency determination was arbitrary.

capricious and contrary to the law. The DAQ approval of the equipment modification: 1) violates Condition 4 of the AO and the public notice and comment requirements of Utah Admin. Code R307-401-7; 2) fails to reconcile Condition 4 and Condition 7 as is required by a plain reading of the AO; 3) relies on an "equivalency" determination that is not supported by the Administrative Record, and is incorrect based on undisputed facts in the record; and 4) allowing the change in technology, as proposed by IPSC, will violate the AO.

Under Condition 4 of the AO, DAQ's Approval of the Supercritical Technology Change is Unlawful.

Condition 4 of the AO provides that "[m]odifications to the equipment or processes approved by this AO that **could affect** the emissions covered by this AO must be reviewed and approved in accordance with R307-401-1."[30] Condition 4 reflects the purpose and the letter of the Utah Air Conservation Act, as well as the Clean Air Act, to **prevent** air pollution.[31] Therefore, where a modification "could affect" emissions – either by increasing them or decreasing them – the Executive Secretary must reexamine the AO according to R307-401-1, always with the goal of preventing pollution if the law so dictates.

That the basic technology change for Unit 3 from subcritical to supercritical PC coal fired power unit "could affect the emissions" covered by the AO is without doubt. Therefore, under its own terms and conditions, the AO "must be reviewed and approved"

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[30] Exhibit 1 at 3, AR IPSC 4334 (emphasis added).

[31] Utah Code Ann. § 19-2-101(4)(a) (stating the purpose of the Act as to "provide for a coordinated statewide program for air pollution prevention, abatement, and control."); see also 42 U.S.C. § 7401(c) (Congressional declaration that the primary purpose of the Clean Air Act is air pollution prevention).

pursuant to Rule R307-401-1.[32] R307-401-1 sets out detailed "application and permitting requirements for new installation," including public notice requirements. Utah Admin. Code R307-401-7. As DAQ did not comply with these requirements prior to its acquiescence to the technology change, its decision and the AO modification is unlawful.

IPSC itself states that emissions "could change" if Unit 3 were a supercritical rather than a subcritical boiler. For example, in its August 4, 2006 letter requesting the change to supercritical technology, IPSC states plainly: "Installation of a supercritical boiler **will result in a net decrease in emissions** as measured in lb/MWh." Exhibit 5 at 3, AR IPSC 4475 (emphasis added); see also Exhibit 8 (Koucky Declaration), ¶ 5 (agreeing with IPSC statement and stating "[b]ecause a supercritical boiler is more thermally efficient, this technology should produce[] lower emissions of criteria pollutants and carbon-dioxide per megawatt generated when compared to a subcritical boiler in the same operation."). Again, in response to Sierra Club's May 20, 2004 comment on the draft AO that DAQ was obligated to consider supercritical boiler technology as BACT because of reduced emissions of CO_2 and criteria pollutants, IPSC affirmed:

> With the low proposed emission limits for SO_2, NO_X, and particulates [in the draft AO], the actual reduction in tons per year does not warrant the increase in capital costs, safety, and equipment compatibility issues associated with a supercritical boiler.

Exhibit 3, AR at 3891. Thus, IPSC concedes that "a net decrease in emissions as measured in lb/MWh" and "actual reductions in tons per year" of SO_2, NO_X, and

[32] Utah Admin.Code R307-401-1 states in part: "This rule establishes the application and permitting requirements for new installations and modifications to existing installations throughout the State of Utah."

particulates can be realized with the installation of a supercritical boiler for Unit 3.[33] This plainly meets the standard of Condition 4 that the proposed change in equipment – to supercritical technology – "could affect" emissions, thereby triggering review and approval in accordance with R307-401-1. Exhibit 1 at 3, AR IPSC 4334 (Condition 4).

IPSC's statements also reflect the conclusions of comprehensive analysis undertaken by EPA.[34] In its thorough comparison of the environmental impacts and costs of various types of power generation plants, including subcritical and supercritical boilers, EPA found that supercritical boilers produce substantially less SO_2, NO_X, CO, VOCs, particulate matter (including PM_{10}), lead, mercury, and acid mist, as well as less CO_2 and solid waste when measured in pounds per megawatt hour. Exhibit 9, EPA Doc at 3-21 to 3-22.[35] Importantly, when these rates are compared to those in the AO also expressed in pounds per hour, the emission rates for the supercritical boiler are lower than those in the AO. Exhibit 1 at 6, AR at 4337 (Condition 9).

Thus, based on IPSC's own admissions, the change in technology from a subcritical to a supercritical boiler **will** affect emissions covered by the AO. As a result, R307-401-1 is triggered and public notice and comment, as well as other detailed review procedures – including setting more stringent emissions limits in the permit – are

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[33] That emission of pollutants would be reduced was the basis for Sierra Club's comments on the failure of DAQ to complete BACT analysis for a supercritical boiler for Unit 3. Exhibit 7, AR at 4496.

[34] In July 2006, EPA issued a report entitled "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies." The complete report is available at http://www.epa.gov/air/caaac/coaltech/2007_01_epaigcc.pdf and portions are attached to this memorandum at Exhibit 9 (referenced as "EPA Doc").

[35] Mr. Koucky also states that EPA has found in its July 2006 Report that "supercritical PC technology results in lower expected emissions expressed in pound per megawatt hour." Exhibit 8, ¶ 7.

required before the modification can be approved. The Executive Secretary's failure to meet his R307-401-1 obligations is unlawful and the AO must be remanded.

Condition 4 Remains in Effect Despite Any Purported Equivalency Determination.

In his letter approving the Unit 3 technology change, the Executive Secretary stated that, under Condition 7, supercritical boiler technology is "equivalent" to the subcritical technology permitted by the AO. Exhibit 6, AR IPSC 4478. This equivalency determination, in turn, served as an approval of the design change. Condition 7 requires for Unit 3 the installation of a subcritical unit – a dry-bottom pulverized coal fired boiler – or the equivalent equipment. Exhibit 1 at 3-4, AR IPSC 4334-35. Thus, in finding the supercritical boiler equivalent to the subcritical boiler, the Executive Secretary sanctioned the substitution of one technology for another.

However, Condition 4 still applies and must be understood in concert with Condition 7. Condition 4 requires compliance with R307-401-1 whenever "modifications to the equipment or processes approved by this AO . . . could affect" regulated emissions. Exhibit 1 at 3, AR at 4334. Read together, Condition 4 **and** Condition 7 dictate that even where there is a substitution of "equivalent equipment," if this "modification to the equipment or processes . . . could affect" emissions, compliance with R307-401-1 is required prior to approval of the change. This is the only way to give effect to the two AO conditions. Moreover, there is nothing in the AO, or Condition 7 specifically, to suggest that Condition 7 somehow trumps Condition 4. This further underscores that the two Conditions must both be given meaning.

In addition, there is nothing in DAQ's regulations to suggest that, particularly as applied here by the Executive Secretary, Condition 7 is appropriate. The regulations do

not foresee a situation where the Executive Secretary has authority to modify an AO, previously approved under the detailed provisions of R307-401-1, to allow a change to basic design of the facility that "could affect" emissions, while sidestepping his R307-401-1 obligations. This effort to take a modification of an AO out of the R307-401-1 is not in keeping with DAQ regulations or the guarantee of these rules that the public will be allowed to participate in important permitting decisions that affect Utah's airsheds.

Given that Condition 4 cannot be ignored based on an "equivalency determination," the Executive Secretary violated, or sanctioned the violation of, the Condition by allowing supercritical technology substitution without compliance with Utah Admin. Code R307-401-1. As a result, his decision runs afoul of the AO and is unlawful, arbitrary and capricious.

As Proposed by IPSC, the Supercritical Boiler is Not Equivalent to the Approved Subcritical Boiler.

As established above, Condition 4 is not nullified by an equivalency determination. In any case, however, the record shows that the supercritical boiler, as proposed by IPSC, is **not** equivalent to the permitted subcritical boiler. Therefore, the Executive Secretary's determination of equivalency is invalid and cannot justify the technology change.

In response to IPSC's request for permission to replace the technology for Unit 3, the Executive Secretary stated that "a supercritical PC boiler is equivalent to the permitted unit." Exhibit 6, AR at 4478. For several reasons, this conclusion is arbitrary. First, there is nothing in the record to support this conclusion or to provide a basis for it. See Exhibit 2.

The Executive Secretary has given no explanation for his determination. Therefore it is not supported by the Administrative Record and must be rejected. This is particularly true given the paucity of information and analysis on which the "equivalency" assessment was apparently based – the August 4, 2006 letter. The August 4, 2006 letter gives perfunctory treatment to BACT analysis, and does not even provide a source of its efficiency analysis and fails to suggest type of coal being considered. Exhibit 5 at 3, AR IPSC 4475 (discussion of BACT); Exhibit 5 at 2, AR IPSC 4474 (efficiency). That the Administrative Record is inadequate to support an "equivalency" determination is also underscored by the fact that both DAQ and IPSC adamantly rejected supercritical technology for Unit 3. Exhibit 4, AR IPSC 4297 (DAQ); Exhibit 3, AR IPSC 3891(ISPC). To justify such a reversal in position requires more than silence in the record and a refusal to allow the public to weigh in on the analysis.[36]

Second, what the record **does** show is that the supercritical boiler, as proposed by IPSC, is **not** equivalent to the permitted subcritical boiler.[37] This is because, as IPSC itself attests, the supercritical boiler will be more efficient than the subcritical boiler. Exhibit 5 at 2, AR IPSC 4474. While IPSC calculates this increased efficiency at 2 to 3 percent, id., a more accurate determination is that the supercritical boiler will be approximately 7 to 9 percent more efficient than the subcritical boiler. Exhibit 9, EPA Doc at 3-3; Exhibit 10 (Thompson Declaration), ¶¶ 8-11. In any case, as IPSC states, the

[36] Sierra Club reiterates that, in this motion for summary judgment, the undisputed fact that a supercritical boiler could result in lower emissions is sufficient for a remand to DAQ for review of the modification and re-analysis of BACT. Sierra Club is **not** arguing in this motion what form that BACT analysis should take.

[37] Of course, because a supercritical boiler "could affect" emissions by resulting in lower emissions, it is not equivalent to a subcritical boiler. Therefore, for all the reasons that Condition 4 is triggered by the technology change, Condition 7 cannot be met.

improved efficiency of the supercritical design "increas[es] the power output of the steam turbine-generator for the same coal burned in the boiler." Exhibit 5 at 2, AR IPSC 4474. Yet, IPSC also states in its design change proposal that it will **not** increase the heat input rate or the coal feed rate in the AO. Exhibit 5 at 2 and "Exhibit 1," AR IPSC 4474, 4477. This means, based on IPSC's own statements, with the same amount of coal being burned in the supercritical boiler, the power output will be increased. Id.

EPA's exhaustive comparison of subcritical and supercritical boilers bears this out. In that comparison, the federal agency determined that a supercritical unit using bituminous coal[38] has a net thermal efficiency (HHV) of 38.3 percent, and for subbituminous coal, of 37.9 percent. Exhibit 9, EPA Doc at 3-3. Importantly, EPA was examining a pulverized coal plant with supercritical steam conditions of 3,500 psig and 1050/1050ºF double reheat,[39] a configuration almost perfectly analogous to that suggested by IPSC. Exhibit 5 at 2, AR IPSC 4474. Using IPSC's figure for the efficiency of the subcritical boiler (with no coal type specified)[40] and EPA's numbers for the supercritical boiler reveals a efficiency increase of 7 percent for a supercritical boiler burning bituminous coal and a 6 percent efficiency for subbituminous coal.[41] Exhibit 9, EPA Doc at 3-3; AR IPSC 4474 (IPSC figures); Exhibit 10 (Thompson Declaration), ¶ 9.

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[38] Condition 19 of the AO limits fuel for Unit 3 to either "bituminous or blend of bituminous and up to thirty percent subbituminous coals."

[39] Exhibit 9, EPA Doc. at 1-1.

[40] The thoroughness of the EPA analysis coupled with IPSC's failure to provide a basis for its efficiency calculation or assumptions, such as coal type, underlying the calculation, underscores that the characteristics of these technologies must be understood at a deep level. This complexity confirms that the Executive Secretary must independently examine these figures and that the public must be given the chance to comment on this analysis.

[41] EPA bases its efficiency figures on a PC boiler with subcritical steam conditions of 2400 psig/1000/1000ºF. This is almost identical to IPSC's assumption of 2520 psig/1050/1050ºF. Exhibit 9, EPA Doc at 3-3; Exhibit 5 at 2, AR IPSC 4474.

Using EPA's figures for the PC boiler leads to a net efficiency increase of 6.7 percent and 8.9 percent from a subcritical to supercritical boiler using bituminous and subbituminous coal respectively.[42] Exhibit 9, EPA Doc at 3-3; Exhibit 10 (Thompson Declaration), ¶ 10.

Taking these conclusions together establishes that a supercritical Unit 3, operated as requested by IPSC, will be producing somewhere between 64 to 84 more megawatts than the subcritical Unit 3 approved in the AO. Exhibit 9, EPA Doc 3-3; Exhibit 10 (Thompson Declaration), ¶ 11. Said another way, a supercritical Unit 3 will be a 1014 to 1034 megawatt facility, instead of a 950 gross megawatt unit as approved by the AO. Id. This means supercritical technology for Unit 3 is not equivalent to subcritical technology – equipment that allows a plant to generate 1014 to 1035 megawatts is **not** equivalent to equipment that allows a plant to generate 950 megawatts. Exhibit 10 (Thompson Declaration), ¶ 12. As a result, the Executive Secretary's determination otherwise cannot withstand scrutiny.

Third, the two technologies are not equivalent because a proper BACT analysis for a supercritical boiler could and would lead to lower emission limits – or, at the very least, that BACT must be revisited for the supercritical technology. In requesting permission to build Unit 3 using a supercritical boiler, IPSC has admitted both that this supercritical design is technically feasible and not an excessive economic burden. Exhibit 5, AR IPSC 4473-4477 (August 4, 2006 Letter); Exhibit 3, AR IPSC 3891 (IPSC

[42] Interestingly, IPSC bases its net plant efficiency of 36.75 percent on a supercritical boiler design which "**typically** has a 3500 psig/1050/1100ºF steam power cycle . . . ." Exhibit 5 at 2, AR IPSC 4474 (emphasis added). This means that IPSC has **not** specified the exact design of the Unit 3 supercritical boiler, but assumes a design almost identical to that assumed by EPA.

noting that economic considerations disfavored supercritical technology). Moreover, as IPSC admits and EPA confirms, a supercritical boiler has lower hourly emissions. See supra pages 17-18, 22-23. These factors together demonstrate that the modified AO's BACT analysis is flawed for not requiring lower emission rates, Exhibit 8 (Koucky Declaration), ¶ 9, and mandates that a new BACT analysis for the project is required. This, in turn means that the two technologies are **not**, and cannot be, equivalent.

Fourth, the supercritical boiler, as proposed by IPSC, cannot be equivalent to the previously-approved subcritical boiler because the AO terms and conditions written for the subcritical technology do not make sense when applied to the supercritical technology. For example, to determine the 633.5 lb/hr NO_x emission limit of Condition 9, DAQ multiplied the maximum heat input rate of the Unit 3 boiler (9050 MMBtu/hr) by the NO_x BACT emission limit for a 30-day rolling average (0.07 lb/MMBtu). Exhibit 1 at 5-6, AR IPSC 4336-37. If IPSC were to operate the supercritical boiler to produce the 950 megawatts gross authorized in the AO, then the maximum heat input capacity of the supercritical boiler would be lower for the purposes of this calculation. This means that, using DAQ's own analysis, the pound per hour NO_x limit should be lower to reflect the decreased heat input. Should the pound per hour NO_x limit be held the same, while the technology is changed, the permit terms would also no longer reflect reality and therefore would be arbitrary.[43]

Thus, examined from every angle, the undisputed facts establish that the Executive Secretary's equivalency determination is invalid. It lacks any basis in the

[43] Of course, if the maximum heat input for the supercritical boiler were not lowered, but allowed to stay the same, then Unit 3 would no longer be a 950 gross megawatt facility, but would be a 1007 or 1035 megawatt facility, and again, the AO would not reflect reality and would be arbitrary.

record. The conclusion conflicts with IPSC's own statements and is contrary to EPA's comprehensive analysis of the increased efficiency of supercritical boilers compared to subcritical units. As a result, the Executive Secretary's conclusion must be rejected in favor of a finding that supercritical technology, as proposed by IPSC is not equivalent to the subcritical equipment authorized by the AO.

Approval of Unit 3 as a Supercritical Boiler Will Violate the AO.

Condition 6 of the AO states that IPSC "**shall** install and operate the nominal 950 gross-MW power generating Unit 3 with dry-bottom pulverized coal fired boiler . . . as defined by this AO, in accordance with the terms and conditions of this AO . . . ." Exhibit 1 at 3, AR IPSC 4334. If allowed, as IPSC requested and the Executive Secretary approved, to install a supercritical boiler and to keep coal feed rate and heat input the same, IPSC will not be operating a 950 megawatt power generating unit. Instead, it will be operating a 1007 to 1036 megawatt power generating unit. As approval of this technology and this heat input rate will violate Condition 6 of the permit, the August 2006 modification to the AO is invalid.

CONCLUSION

For the foregoing reasons, on the undisputed facts in the record, the AO to construct Unit 3 is invalid, and the DAQ's decision to approve a modification to supercritical boiler technology was arbitrary, capricious, and contrary to law. Sierra Club requests that the Board grant summary judgment on the claims in Statements of Reasons # 20, # 21, and # 22 and remand this matter to the DAQ for IPSC to submit a revised Notice of Intent to DAQ, based on current circumstances and conditions, to obtain approval to construct the proposed plant.

Dated: February 26, 2007

___/s/_____
JORO WALKER
DAVID BECKER
Attorneys for Utah Chapter of the Sierra Club

CERTIFICATE OF SERVICE

I hereby certify that on this 26th day of February 2007, I caused a copy of the foregoing Motion for Summary Judgment and Memorandum in Support of Motion to be emailed to the following:

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fnelson@utah.gov

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__/s/_____
DAVID BECKER
Attorney for Sierra Club

List of Exhibits – Sierra Club's Motion for Summary Judgment and Memorandum in Support of Motion – IPSC

1. Unit 3 Approval Order (AR IPSC 4331)
2. Final Preliminary Index to Administrative Record
3. IPP Response to Public Comments (Incl AR IPSC 3891)
4. Milka memo responding to comments (AR 4297)
5. August 4, 2006 UAMPS letter (AR IPSC 4473)
6. August 17, 2006 DAQ approval letter (AR IPSC 4478)
7. Sierra Club First Am Req for A A (AR IPSC 4496)
8. Koucky Declaration
9. EPA Doc
10. Thompson Declaration

EXHIBIT 1

State of Utah

Department of
Environmental Quality

Dianne R. Nielson, Ph.D.
Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

OLENE S. WALKER
Governor

GAYLE F. McKEACHNIE
Lieutenant Governor

DAQE-AN0327010-04*

October 15, 2004*

George W. Cross
Intermountain Power Service Corporation
850 West Brush Wellman Road
Delta, Utah 84624-9522

Dear Mr. Cross:

Re: Approval Order: PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station, Millard County, Utah CDS-A, ATT, NSPS, HAPs, MACT, Title IV, Title V Major. Project Code: N0327-010

The attached document is the Approval Order (AO) for the above-referenced project.

Future correspondence on this Approval Order should include the engineer's name as well as the DAQE number as shown on the upper right-hand corner of this letter. Please direct any technical questions you may have on this project to Ms. Milka M. Radulovic. She may be reached at (801) 536-4232.

Sincerely,

Richard W. Sprott, Executive Secretary
Utah Air Quality Board

RWS: MR:jc

cc: Central Utah Public Health Department
Mike Owens, EPA Region VIII

*On November 12, 2004, IPSC petitioned the Utah Air Quality Board for review of Condition 24 in the Approval Order DAQE AN0327-04 (AO) dated October 15, 2004, that was issued to IPSC to add new Unit 3. Settlement negotiations took place between UDAQ and IPSC, resulting in a Joint Stipulation. The Approval Order incorporates the terms of the Joint Stipulation, which was approved by Order of the Air Quality Board on September 7, 2005.

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

APPROVAL ORDER: PSD MAJOR MODIFICATION TO ADD NEW UNIT 3 AT INTERMOUNTAIN POWER GENERATING STATION

Prepared By: Milka M. Radulovic, Engineer
(801) 536-4232
Email: milkar@utah.gov

APPROVAL ORDER NUMBER

DAQE-AN0327010-04

Date: October 15, 2004

Intermountain Power Service Corporation
Source Contact
George Cross
(435) 864-4414

Richard W. Sprott
Executive Secretary
Utah Air Quality Board

Abstract

On November 12, 2004, IPSC petitioned the Utah Air Quality Board for review of Condition 24 in the Approval Order DAQE AN0327-04 (AO) dated October 15, 2004, that was issued to IPSC to add new Unit 3. Settlement negotiations took place between UDAQ and IPSC, resulting in a Joint Stipulation. The Approval Order incorporates the terms of the Joint Stipulation, which was approved by Order of the Air Quality Board on September 7, 2005.

Intermountain Power Service Corporation (IPSC) currently operates the Intermountain Power Plant (IPP) located near the town of Delta, Utah. The existing plant has two drum-type, pulverized coal (PC)-fired boilers that provide steam to two power-generating units, designated as Unit 1 and Unit 2, each with nominal gross capacity of 950 MW. The Intermountain Power Service Corporation (IPSC) submitted a Notice of Intent to expand the IPP facility by adding one additional base load pulverized coal fired electricity generating Unit 3, designed at nominal 950-gross MW (900-net MW) with a dry bottom, tangentially fired or wall-fired boiler and associated equipment. The Unit 3 boiler will be equipped with wet flue gas desulphurization (WFGD), selective catalytic reduction (SCR), and baghouses for control of the various emissions.

This project is a major modification for the Prevention of Significant Deterioration (PSD) regulations. On site meteorological monitoring, air dispersion modeling, air quality impacts analysis including visibility and PSD class I and II impacts analysis, non-attainment boundary impact analysis, and a complete top-down Best Available Control Technology (BACT) review were completed and submitted by the IPSC as a part of their Notice of Intent (NOI). Also, an application for case-by-case maximum achievable control technology (MACT) determination for hazardous air pollutants (HAPs) was provided as a part of the NOI. Unit 3 is also subject to New Source Performance Standards under 40 Code of Federal Regulations (CFR) 60, Subparts A, Da and Y. Title IV and Title V of the 1990 Clean Air Act apply to this modification and the Title V permit shall be amended prior to the operation of the Unit 3. Unit 3 boiler will be classified Group1, Phase II under the Acid Rain Program. The increment analysis indicated that the amount of PM_{10} 24-hour increment consumed by the proposed project would be less than 50% of the standard; therefore, approval under Utah Administrative Code R307-401-6 (3) from the Utah Air Quality Board was not required. The IPP will meet all primary and secondary National Ambient Air Quality Standards (NAAQS). The IPP will also meet Class I increments in the National Parks in southern Utah and Class II PSD increments in the vicinity of the plant. IPP Unit 3 will have no adverse effect on air quality related values (including visibility) on any Class I areas.

The IPP is located in Millard County, an attainment area for all criteria pollutants.

Estimated potential to emit totals from Unit 3, in tons per year, are as follows: PM_{10} (filterable) = 496.5, NO_x = 2,775, SO_2 = 3,567.5, CO = 5,946, VOC = 107, HAPs = 199

The project has been evaluated and found to be consistent with the requirements of the Utah Administrative Code Rule 307 (UAC R307). A public comment period was held in accordance with UAC R307-401-4 and comments were received. The comments were evaluated and the Approval Order was modified to incorporate those comments. This air quality Approval Order (AO) authorizes the project with the following conditions, and failure to comply with any of the conditions may constitute a violation of this order.

<u>General Conditions:</u>

1. This Approval Order (AO) applies to the following company:

Site Location
Intermountain Power Service Corporation
850 West Brush Wellman Road
Delta, UT 84624-9522

Corporate Office Location
Intermountain Power Service Corporation
850 W. Brush Wellman Road
Delta, UT 84624

Phone Number: (435) 864-4414
Fax Number: (435) 864-6670

The equipment listed in this AO shall be operated at the following location:

850 West Brush Wellman Road, Delta, Millard County, Utah

Universal Transverse Mercator (UTM) Coordinate System: datum NAD27
4,374.4 kilometers Northing, 364.2 kilometers Easting, Zone 12

2. All definitions, terms, abbreviations, and references used in this AO conform to those used in the Utah Administrative Code (UAC) Rule 307 (R307) and Title 40 of the Code of Federal Regulations (40 CFR). Unless noted otherwise, references cited in these AO conditions refer to those rules.

3. The limits set forth in this AO shall not be exceeded without prior approval in accordance with R307-401.

4. Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved in accordance with R307-401-1.

5. All records referenced in this AO or in applicable NSPS and/or NESHAP and/or MACT standards, which are required to be kept by the owner/operator, shall be made available to the Executive Secretary or Executive Secretary's representative upon request, and the records shall include the five-year period prior to the date of the request. Records shall be kept for the following minimum periods:

A.	Used oil consumption	Five years
B.	Emission inventories	Five years from the due date of each statement or until the next inventory is due, whichever is longer.
C.	All other records	Five years

6. Intermountain Power Service Corporation (IPSC) shall install and operate the nominal 950 gross-MW power generating Unit 3 with dry-bottom pulverized coal fired boiler and modified equipment associated with Unit 3, as defined by this AO, in accordance with the terms and conditions of this AO, which was written pursuant to IPSC's Notice of Intent submitted to the Division of Air Quality (DAQ) on December 16, 2002 and significant additional information provided throughout the process.

7. The approved installations shall consist of the following equipment or equivalent*:

A. Unit 3 Dry-bottom Pulverized Coal Fired Boiler for base load operation with Overfire Air Ports System

Maximum Heat Input Rate:	9050×10^6 Btu/hr
Type of Burner:	Ultra Low NO_x Burners or equivalent

B. Unit 3 Main Boiler Stack

Stack Height:	At least 712 feet, as measured from ground level at the base of the stack.

C. Unit 3 Main Boiler Control Equipment:

C.1 Boiler Stack Fabric Filter Baghouse

C.2 Wet Limestone Flue Gas Desulfurization System (WFGD) built in redundancy

C.3 Selective Catalytic Reduction System with ammonia injection

D. Two Unit 3 Cooling Towers, 3A and 3B, equipped with mechanical Mist Eliminators rated at 0.0005 percent circulating water drift loss.

E. Unit 3 Coal Handling:

E.1 Modification of existing conveyors: higher capacity motors on Belts 7 and 8, Belts 9A/9B, 15A/15B expanded to 48"wide;

E.2 New Unit 3 36"wide Conveyors-16A/16B, 17A/17/B, en mass chain totally enclosed conveyors 301A/B, 302A/B, 303, 304, 305, and 306.

E.3 New Coal Transfer Building #5 with Dust Collector EP-127.

E.4 New Coal East Storage Silos 301, 302, 303, 304, and Coal East Storage Silo Bay Dust Collector EP-128.

E.5 New Coal West Storage Silos 305, 306, 307, 308 and Coal West Storage Silo Bay Dust Collector EP-129.

F Unit 3 Fly Ash Handling Equipment: To convey Fly Ash from the fabric filter to the storage silo:

F.1 Fly Ash Storage Silo 1C with Sealed Loading Spout Vent Dust Collector EP-171

F.2 Fly Ash Storage Silo 1C with Vent Dust Collector EP-172

G. Unit 3 Bottom Ash Handling System to convey bottom ash from boiler to storage area.

H. Unit 3 Limestone Handling System for WFGD system

I. Unit 3 WFGD Sludge Handling System

J. Existing Auxiliary Boiler Modification:
Installation of an extension on each boiler stack so that each stack height is at least 72 feet, as measured from the ground level at the base of the stack.

K. Unit 3 Water Treatment Plant, Steam System, Turbine generator, and Air heaters**

* Equivalency shall be determined by the Executive Secretary.

** This equipment is listed for informational purposes only. There are no emissions from this equipment.

8. Intermountain Power Service Corporation shall notify the Executive Secretary in writing when the installation of the equipment listed in Condition #7 has been completed and is operational, as an initial compliance inspection is required. To insure proper credit when notifying the Executive Secretary, send your correspondence to the Executive Secretary, attn: Compliance Section.

If construction and/or installation has not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11.

Limitations and Tests Procedures

9. Emissions to the atmosphere from the indicated emission point(s) shall not exceed the following rates and concentrations:

Source: Unit 3 Main Boiler Stack, BACT/MACT		
Pollutant	Emission Rate (lb/MMBtu)	Averaging Period
SO_2	0.10	24-hour block average
SO_2	0.09	30-day rolling average
NO_x	0.07	30-day rolling average
PM_{10} (filterable)	0.012	3-test run average
PM (filterable)	0.013	3-test run average
CO	0.15	30-day rolling average
VOC	0.0027	3- test run average
H_2SO_4	0.0044	24-hour block average
Fluorides/HF	0.0005	3- test run average
Lead	0.00002	3- test run average
Hg- bituminous coal*	6×10^{-6} lb/ MWhr	12-month rolling average
Hg- subbituminous coal*	20×10^{-6} lb/ MWhr	12-month rolling average

Source: Unit 3 Main Boiler Stack, Air Quality Modeling		
Pollutant	Emission Rate (lb/hr)	Averaging Period
SO_2	1,357.5	3-hour block average
NO_x	633.5***	24-hour block average
PM_{10} (filterable+condensable)	221***	24-hour block average**
CO	3,000	8-hour block average
HCL	38.13 lb/hr	3-test run average

*If a blend of bituminous and subbituminous coals is used, the Hg emission limitation for the blend will be determined by 40 CFR 63.9990(a)(5) (Proposed Rules, Federal Register, Vol. 69, No. 20, January 30, 2004, pages 4720-4721).

**Based on a 24-hour test run or any method approved by the Executive Secretary, which will provide 24-hour data.

*** During periods of startup and shutdown Condition 13 and Condition 24 shall apply.

24-hour block means the period of time between 12:01a.m. and 12:00 midnight.

8-hour block average means eight consecutive hours.

10. Stack testing to show compliance with the emission limitations stated in the above condition shall be performed as specified below:

A.

Emissions Point	Pollutant	Testing Status	Test Frequency
Unit 3 Main Boiler Stack	PM_{10} (f)/PM_{10} (f+c)	Initial	Annual
	PM (f)	Initial	Annual**
	SO_2	Initial	CEM
	NO_x	Initial	CEM
	CO	Initial	CEM*
	H_2SO_4	Initial	Annual
	VOC	Initial	Annual
	Fluorides/HF	Initial	60-months
	Lead	Initial	60-months
	HCl	Initial	60-months
	Hg	Initial	Hg CEM***

f-filterable; c-condensible

*or may use CEM equivalent, such as parametric monitoring that may be approved by the Executive Secretary

**or parametric monitoring that may be approved by the Executive Secretary

*** 40 CFR 60, Appendix B, Performance Specification 12a (CEM) (Proposed Rules, Federal Register, Vol. 69, No. 20, January 30, 2004, page 4744) or 40 CFR 63, Appendix B, Method 324 (Sorbent Trap Sampling) (Proposed Rules, Federal Register, Vol. 69, No. 20, January 30, 2004, page 4736) or other testing methods that may be approved.

B. Testing Status (To be applied to the source listed above)

Initial: Initial compliance testing is required. The initial test date shall be performed as soon as possible and in no case later than 180 days after the start up of a new emission source.

Records & Miscellaneous

24. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this Approval Order including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Executive Secretary which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, inspection of the source, and records required in Condition 13. All maintenance performed on equipment authorized by this AO shall be recorded.

25. The owner/operator shall comply with R307-150 Series. Inventories, Testing and Monitoring.

26. The owner/operator shall comply with R307-107. General Requirements: Unavoidable Breakdowns.

The Executive Secretary shall be notified in writing if the company is sold or changes its name.

Under R307-150-1, the Executive Secretary may require a source to submit an emission inventory for any full or partial year on reasonable notice.

This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including R307.

A copy of the rules, regulations and/or attachments addressed in this AO may be obtained by contacting the Division of Air Quality. The Utah Administrative Code R307 rules used by DAQ, the Notice of Intent (NOI) guide, and other air quality documents and forms may also be obtained on the Internet at the following web site: http://www.airquality.utah.gov/

The annual emissions estimations below are for the purpose of determining the applicability of Prevention of Significant Deterioration, non-attainment area, maintenance area, and Title V source requirements of the R307. They are not to be used for determining compliance.

The Potential to Emit (PTE) emissions for the entire Unit 3 operations are currently calculated at the following values:

	Pollutant	Tons/yr
A.	PM_{10} (filterable)	496.5
B.	SO_2	3,567.5
C.	NO_x	2775
D.	CO	5946
E.	VOC	107
F.	H_2SO_4	174
G.	Lead	0.79
H.	Total Reduced Sulfur	29
I.	Reduced Sulfur Compounds	29

HAPs

Mercury	0.0413
Hydrochloric Acid (HCL)	167.01
Fluorides/HF	20
Total HAPs	199

Approved By:

Richard W. Sprott, Executive Secretary
Utah Air Quality Board

EXHIBIT 2

PAUL M. McCONKIE #5881
CHRISTIAN C. STEPHENS #9068
Assistant Attorneys General
MARK SHURTLEFF #4666
Utah Attorney General
160 East 300 South, 5th Floor
P.O. Box 140873
Salt Lake City, Utah 84114-0873
(801) 366-0290
Counsel for the Executive Secretary,
Air Quality Board of Utah

BEFORE THE UTAH AIR QUALITY BOARD

In the Matter of: Unit 3, Intermountain Power Service Corporation, Millard County, Utah DAQE-AN0327010-04	EXECUTIVE SECRETARY'S IDENTIFICATION OF THE ADMINISTRATIVE RECORD

The Executive Secretary has identified the documents in the attached index as the Executive Secretary's Administrative Record in the above-captioned matter as of January 4, 2007, the date of the Executive Secretary's Response to Sierra Club's Amended Request for Agency Action. As of today's date, the documents are available to all parties for inspection and copying at the Department of Environmental Quality, Division of Air Quality, 150 North 1950 West, Bldg #1, Salt Lake City, Utah.

Dated this 6TH day of FEBRUARY, 2007.

Paul M. McConkie
Christian C. Stephens
Assistant Attorneys General, for
the Executive Secretary

In the Matter of:

AGENCY ADMINISTRATIVE RECORD

Abbreviations used:

DAQ is the Division of Air Quality
IPSC is the Intermountain Power Service Corporation
DEQ is the Department of Environmental Quality
IPA is the Intermountain Power Agency
BLM is the Bureau of Land Management
IPP is the Intermountain Power Project
NPS is the National Park Service

Record Description	Date	Added to Record By	Record page [IPSC]
Letter to Rand Crafts, IPSC, from Tom Orth, Air Quality Modeler, Technical Analysis Section, DAQ	08/01/01	DAQ	0001
Proposed Protocol for a Class II Area Air Quality Modeling Analysis of the Intermountain Power Project Unit #3 Project prepared by CH2M Hill on behalf of Intermountain Power Agency	02/14/02	DAQ	0002-0028
Letter to Rand J. Crafts, IPSC, from Tom Orth, Air Quality Modeler, Technical Analysis Section, DAQ re Review of the modeling protocol for the proposed IPSC - 875 megawatt coal-fired power generation Unit #3 near Delta, Utah	02/27/02	DAQ	0029
Air Quality Criteria for Oxides of Nitrogen Summary of Vegetation Impacts [presentation made by Jon Knodel EPA region VII]	05/13/02	DAQ	0030-0039
Attendance list IPA/UDAQ Meeting	10/22/02	DAQ	0040
Performance Audits of Air Quality Equipment at the Intermountain Power Service Corporation Delta, Utah Monitoring Station prepared for Intermountain Power by Meteorological Solutions Inc.	10/02	DAQ	0041-0071
Letter to Tom Orth, DAQ, from James (Josh) Nall, Air Quality Meteorologist, CH2M Hill re CALPUFF Modeling Files for the IPP Unit #3 Project	11/20/02	DAQ	0072-0077
Letter to Rand Crafts, IPSC from James [Josh] Nall, Air Quality Meteorologist, CH2M Hill re IPP Over-Fire Air Project: Carbon Monoxide Impacts	11/25/02	DAQ	0078-0086

Record Description	Date	Added to Record By	Record page [IPSC]
Summary of Meteorological and Air Quality Data at Intermountain Power Service Corporation's Delta, Utah Monitoring Station July, 2001 - October, 2002 Appendices A-D prepared by Meteorological Solutions Inc. on behalf of Intermountain Power	11/02	DAQ	0087-0460
IPA Pre-NOI Meeting: Class 1 Area Impacts Agenda and attendance list	12/06/02	DAQ	0461-0462
Notice of Intent, Intermountain Power Project Proposed Unit 3, prepared for IPSC by CH2M Hill. [Entire NOI resubmitted on May 14, 2003 with some supplements. In May 2004 the NOI was supplemented to consolidate technical documents in the Appendix I (Technology Discussion)]	12/02	DAQ	0463-1326
Email to Robert Pearson, CH2M Hill, from Don Shepherd, NPS re Coal-fires Utilities Projects - 11/4/02	12/10/02	DAQ	1327
Letter to William Wagner, Bureau of Land Management, Dennis Haddow, U.S. Forest Service and Don Shepherd, NPS, from Milka M. Radulovic, Environmental Engineer III, New Source Review Section re Notice of Intent for Intermountain Power Project Unit 3 Project Code: N0327-010 (December 2002 NOI not included)	12/26/02	DAQ	1328-1342
DVD - Intermountain Power Plant Unit 3 Modeling Files	Undated	DAQ	1343
Email to Kevin Golden, EPA from Tom Orth, DAQ re IPP - Unit 3	01/10/03	DAQ	1344
Letter to Jan Sensibaugh, Director, Montana Department of Environmental Quality, from Craig Manson, Assistant Secretary for Fish and Wildlife and Parks, United States Department of the Interior re Class I Modeling Protocol	01/10/03	DAQ	1345-1346
Emails between Tom Orth and Kevin Golden, EPA re Intermountain Power Plant - Unit 3	01/13/03	DAQ	1347
White Paper entitled Utah Need Not Follow FLAG Modeling Guidelines Where it Does Not Meet Utah's Policy Choices or Where it Lacks Technical Integrity re Class I Modeling Protocol	undated	DAQ	1348-1354
Agenda IPP Unit #3 DAQ NOI Review Meeting 1	01/16/03	DAQ	1355-1357
Email to Tom Orth from Dave Prey re IPP3 Project:	01/22/03	DAQ	1358

Record Description	Date	Added to Record By	Record page [IPSC]
Basis for ISC and CALPUFF Emission Rates providing comments			
Email to Tom Orth from Josh Nall, CH2M Hill re IPP3 Project: Basis for ISC and CALPUFF Emission Rates	01/23/03	DAQ	1359-1368
Letter to Lynn Menlove, DAQ, from Bill Hauze, QEP, Monitoring Services Manager re questions about the IPSC data report, with enclosed Memo dated July 23, 2002, to George, Linda, Leona, Mike, IPSC file from Bill, Meteorological Solutions Inc. re IPP Precipitation Gauge [letter inadvertently dated January 24, 2002 - should likely have been January 24, 2003 as it was received by DAQ on January 28, 2003]	01/24/03	DAQ	1369-1371
Letter to Lance C. Lee, P.E., Unit 3 Feasibility Manager, IPA, from Tom Orth, Air Quality Modeling Consultant, Technical Analysis Section	03/14/03	DAQ	1372-1376
Wasatch Clean Air Coalition, Utah Chapter Sierra Club, Great Basin Foundation, Rocky Mountain Office of Environmental Defense, Land and Water Fund of the Rockies, Clean Air Task Force Comments on IPSC Notice of Intent for Intermountain Power Project (Dec. 2002) submitted to Rick Sprott, Director, DAQ	04/14/03	DAQ	1377-1529
Letter to Tom Orth, DAQ, from Lance C. Lee, Unit 3 Feasibility Manager, IPA, re Response to UDAQ Comments on Dispersion Modeling for the IPP Unit #3 Project (IPP3)	04/25/03	DAQ	1530-1536
Email to Milka Radulovic (DAQ) from Mike Owens (EPA) re National Coal-Fired Utility NSR Projects Spreadsheet Update	05/16/03	DAQ	1537-1539
Letter to Rick Sprott, Director, DAQ from Reed Searle, IPA, re Replacement Graphics for IPP NOI Addendum submitted on May 14, 2003 (Graphics not included - see NOI)	05/27/03	DAQ	1540-1541
Letters to Kate Kitchell, BLM, Don Shepherd, National Park Services, Chris Hocket, U.S. Forest Service and Mike Owens, Air and Radiation Program, EPA from Milka M. Radulovic (DAQ) re Addendum to the Notice of Intent for IPP Proposed Unit 3 (Addendum to NOI not included - see NOI)	05/29/03	DAQ	1542-1549

Record Description	Date	Added to Record By	Record page [IPSC]
Letter to Rick Sprott, Director, DAQ from Lance C. Lee, IPP Unit 3 Feasibility Manager, IPA re Replacement Sections and Files for the IPP NOI Addendum submitted on May 14, 2003 (Sections not included - see electronic modeling files)	06/18/03	DAQ	1550-1568
Letters to Don Shepherd, NPS, Kate Kitchell, BLM, Chris Hocket, U.S. Forest Service and Mike Owens, Air and Radiation Program, EPA Region 8, from Milka M. Radulovic, DAQ re Replacement Sections and Files for the IPP NOI Addendum Dated May 14, 2003 (Replacements not included - see NOI)	06/20/03	DAQ	1569-1572
Letter to Brock LeBaron, Manager, Technical Analysis Section, DAQ, from Lance C. Lee, Unit 3 Feasibility Manager, IPA, re IPP Unit 3 Utah County PM_{10} Modeling and NAAQS Modeling for CO and NO_2	06/30/03	DAQ	1573-1579
Email to Robert Bachman from Don Shepherd re Power Plant Information attaching Coal-fired Boiler Survey spreadsheets	07/28/03	DAQ	1580-1644
Letter to Brock LeBaron, Manager, Technical Analysis Section, DAQ, from Lance C. Lee, Unit 3 Feasibility Manager, IPA, re IPP Unit 3 Start-Up & Shut-Down Modeling	07/28/03	DAQ	1645-1650
Letter to Tom Orth, DAQ from James (Josh) Nall, Air Quality Meteorologist, CH2M Hill, re Start-Up Modeling Files for the IPP Unit #3 Project	07/29/03	DAQ	1651-1652
Letter to Brock LeBaron, DAQ, from James (Josh) Nall, CH2M Hill re IPP Unit 3 Utah County PM_{10} Modeling	07/31/03	DAQ	1653-1656
Email to Milka Radulovic from Don Shepherd re WYGEN2 baghouse efficiency	08/11/03	DAQ	1657-1658
Email to Milka Radulovic from Don Shepherd re WYGEN2 baghouse efficiency	08/12/03	DAQ	1659-1660
Report entitled PM_{10} Impacts in the Utah County PM_{10} Nonattainment Area Using Calpuff and No Chemical Transformation	10/16/03	DAQ	1661-1725
Email to Milka Radulovic from Don Shepherd re IPP #3 PM cost analysis	10/28/03	DAQ	1726-1727

Record Description	Date	Added to Record By	Record page [IPSC]
Letter to Brock LeBaron, Modeling Section Manager, DAQ, from Lance Lee, IPP Unit 3 Feasibility Manager, IPA, re Replacement Sections and Files for the IPP NOI Addendum submitted on May 14, 2003 (Replacement Sections and Files not included - see NOI)	10/31/03	DAQ	1728
Email to Milka Radulovic from Don Shepherd re Mustang BACT review by NM	11/03/03	DAQ	1729-1733
Technical Memorandum IPP3 Project CALPUFF: Observed Weather Conditions for Days with Natural Obscuration prepared by Josh Nall, Bob Pearson, CH2M Hill	11/06/03	DAQ	1734-1745
Email to Milka Radulovic from Joe Hammond, CH2M Hill re BACT	11/13/03	DAQ	1746-1747
Letter to Chris Shaver, Director, NPS, Attention: Mr. Don Shepherd, Chris Hocket, State and Private Forestry, U.S. Forest Service, Mike Owens, Air and Radiation Program, EPA Region 8 and Kate Kitchell, BLM, from Milka M. Radulovic, New Source Review Section re Replacement Sections and Files for the Notice of Intent Dated May 14, 2003, for IPP to Add Unit 3 (Replacement sections and files not included - see NOI)	11/18/03	DAQ	1748-1755
Email to Milka Radulovic from Kenneth J. Snell, Sargent & Lundy LLC re SO2 Control Efficiency	11/19/03	DAQ	1756-1763
Letter to Reed T. Searle, IPA from Richard W. Sprott, Executive Secretary, Utah Air Quality Board providing list of items currently considered unresolved for the Unit #3 PSD permit	11/24/03	DAQ	1764-1766
Email to Don Shepherd, NPS from Milka Radulovic re SO2 Efficiency	11/24/03	DAQ	1767-1774
Letter to Brock LeBaron, DAQ, from James (Josh) Nall, CH2M Hill re IPP3: Revised Cumulative Class I Increment Modeling	12/16/03	DAQ	1775-1778
Memorandum to Permitting and Planning Branches from Richard W. Sprott re Utah Division of Air Quality (UDAQ) Class I Significant Impact Levels	12/16/03	DAQ	1779-1780
Letter to Richard Sprott, Director, DAQ from Reed T. Searle, General Manager, IPA re IPA IPP Unit 3	12/23/03	DAQ	1781-1919

Record Description	Date	Added to Record By	Record page [IPSC]
[addressing visibility impacts of the IPP Unit 3]			
Memorandum to Milka Radulovic, NSR Engineer, from Tom Orth, Air Quality Modeler re Modeling Analysis Review for the Intermountain Power Association-Over-Fired Air Modification to Unit 1 and 2 - Delta, Utah	12/31/03	DAQ	1920-1924
Memorandum to Milka Radulovic, NSR Engineer, from Tom Orth, Air Quality Modeler re Modeling Analysis Review for the IPA - IPP Unit 3 Addition - Delta, Utah	01/13/04	DAQ	1925-1935
Memorandum to Permitting and Planning Branches from Richard W. Sprott, Director, re Significant Impact Levels for the National Ambient Air Quality Standards and Prevention of Significant Deterioration Class II Analyses	02/27/04	DAQ	1936-1937
DAQ Modified Source Plan Review	03/22/04	DAQ	1938-2110
Letter to Rick Sprott, Director, DAQ, from John Bunyak, Chief, Policy Planning and Permit Review Branch submitting comments	03/25/04	DAQ	2111-2128
Legal Notice of Intent to Approve	03/26/04	DAQ	2129-2132
Letter to Rick Sprott, Director, DAQ, from Jack M. Daly, Project Director	03/26/04	DAQ	2133-2153
Email to Milka Radulovic from Stephen Sands, CH2M Hill re IPP White Papers for NOI Appendix I	03/26/04	DAQ	2154-2157
Letter to George W. Cross, IPSC from Rusty Ruby re Intent to Approve: PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station, Millard County, Utah CDS-A, ATT, NSPS, Hap's, MACT, Title IV, Title V Major. Project Code: N0327-010	04/01/04	DAQ	2158-2171
Emails from Milka Radulovic to Don Shepherd, NPS, and Mike Owens, EPA re IPP Unit 3 (Attachment not included - see record numbers 1938-2110 & 2158-2171)	04/02/04	DAQ	2172-2173

Record Description	Date	Added to Record By	Record page [IPSC]
Letter to Chris Shaver, Director, NPS, Chris Hocket, State and Private Forestry, U.S. Forest Service, Mike Owens, Air and Radiation Program, EPA Region 8 and Kate Kitchell, BLM from Milka M. Radulovic, New Source Review Section, DAQ re Intent to Approve, Engineering Review for Intermountain Power Service Corporation Unit 3 Addition and the Intermountain Power Plant in Delta, Utah (Attachment not included - see record numbers 1938-2110 & 2158-2171)	04/02/04	DAQ	2174-2177
Letter to Rick Sprott, Director, DAQ, from Joro Walker, Esq., Western Resource Advocates re Request for a 20-day Extension of the Public Comment Period on UDAQ's Intent to Approve a PSD Major Modification to Add New Unit 3 at IPP	04/06/04	DAQ	2178
Public Hearing Comments	04/04	DAQ	2179-2280
Legal Notice of Extension of Comment Period	04/15/04	DAQ	2281-2283
Legal Notice of Public Hearing	04/15/04	DAQ	2284-2287
Emails from Milka Radulovic to Don Shepherd, NPS, and Mike Owens, EPA re: Fwd: Three Documents - all Notices to the Millard Chronicle Paper (not included - see record numbers 2129-2132 & 2281-2287)	04/20/04	DAQ	2288-2290
Agenda and Public Hearing Comments re Public Hearing Intent to Approve-IPSC April 29, 2004	04/29/04	DAQ	2291-2312
Public Comment email to Milka Radulovic from Jim Hill re In Favor of IPP Expansion	05/05/04	DAQ	2313
Public Comment email to Milka Radulovic from Jane Beckwith re IPP air quality	05/05/04	DAQ	2314
Comment letter from Ed Phillips, Millard County Sheriff and Citizen, Millard County, Office of the Sheriff	05/05/04	DAQ	2315-2316
Letter to Rick Sprott, Director, DAQ, DEQ, from Stephen Sands, II, P.E., Project Manager re Applicability of EPA's New Modeling Rule Policy to Intermountain Power Project Unit 3 Expansion	05/11/04	DAQ	2317-2348
Comments UGW	05/20/04	DAQ	2349-3356
Letter to Rick Sprott, Director, DAQ, DEQ, from Robert L. Pearson, Ph.D, PE, Vice President, CH2M Hill re Response to National Park Service's Comments on IPP Unit 3 FLAG Modeling	05/21/04	DAQ	3357-3363

Record Description	Date	Added to Record By	Record page [IPSC]
Letter to Milka Radulovic, Permit Review Engineer, DAQ, from CH2M Hill re IPA/IPSC Comments on IPP Unit 3 Intent to Approve Number DAQE-IN0327010-04, Modified Source Plan Review and the Testimony of Other Parties Submitted During Public Comment	05/21/04	DAQ	3364-3395
Letter to Milka Radulovic, Permit Review Engineer, DAQ, from George W. Cross, President & Chief Operations Officer, IPSC re IPSC Comments on Unit 3 Approval Order	05/21/04	DAQ	3396-3400
Email to Milka Radulovic from Cynthia Cody, EPA re extension EPA Comments on Intermountain Power Generating Station	05/21/04	DAQ	3401
Letter to Richard W. Sprott, Executive Secretary, Utah Air Quality Board, from Matthew F. McNulty, III, VanCott re Comments on Intent to Approve PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station DAQE-IN0327010-04	05/21/04	DAQ	3402-3406
Email to Richard Sprott from Mike Owens, EPA EPA comment letter on IPP Unit 3 draft PSD permit	05/24/04	DAQ	3407-3416
Letter to Rick Sprott, Director, DAQ, from Richard R. Long, Director, Air & Radiation Program re Comments on Intent-to-Approve for Unit 3 at Intermountain Power Generating Station	05/24/04	DAQ	3417-3425
Legal Notice of Intent to Approve	05/27/04	DAQ	3426-3433
NPS Comments	05/27/04	DAQ	3434-3461
Letter to Rick Sprott, Director, DAQ, from Congressman Rob Bishop	06/02/04	DAQ	3462
Letter to Mike Owens, EPA - Region 8, from Ed Thatcher, V.P. Engineering	06/09/04	DAQ	3463-3470
Email to Bill Maxwell, EPA from Milka Radulovic re Hg MACT	06/11/04	DAQ	3471
Email to Milka Radulovic from Bill Maxwell, EPA re Hg MACT	06/14/04	DAQ	3472-3475
Email to Brock LeBaron from Tom Orth re IPP Meeting	06/14/04	DAQ	3476-3478
NPS Comments	various	DAQ	3479-3546

Record Description	Date	Added to Record By	Record page [IPSC]
Utah Chapter of Sierra Club, Wasatch Clean Air Coalition, Grand Canyon Trust, Rocky Mountain Office of Environmental Defense, Western Resource Advocates, Clean Air Task Force Supplemental Comments on Intent to Approve DAQE-IN0327010-04 (IPP) and DAQE-IN2529001-04 (Nevco)	06/30/04	DAQ	3547-3714
Letter to Rick Sprott, Director, DAQ, DEQ, from Stephen C. Sands, II, P.E., Project Manager, CH2M Hill re Additional Documents Regarding the Intermountain Power Project Unit 3 Expansion	07/02/04	DAQ	3715-3768
Emails between Milka Radulovic and Bill Maxwell, EPA re Case-by case MACT for 14 HAPs (other than Hg or Ni)	07/04	DAQ	3769-3771
Letter to Rick Sprott, Executive Secretary, DAQ, from James (Josh) Nall, CH2M Hill re Revised PM-10 Increment Modeling for IPP3	07/14/04	DAQ	3772-3775
Utah Chapter of Sierra Club, Wasatch Clean Air Coalition, Grand Canyon Trust, Rocky Mountain Office of Environmental Defense, Western Resource Advocates, Clean Air Task Force Second Supplemental Comment Letter on Intent to Approve DAQE-IN0327010-04 (IPP) and DAQE-IN2529001-04 (Nevco)	07/16/04	DAQ	3776-3872
Email to Milka Radulovic from Don Shepherd, NPS re IPP3 comments	07/30/04	DAQ	3873-3874
IPSC Public Comment Response submitted to Rick Sprott, Executive Secretary, DAQ, UDEQ, by Stephen C. Sands, II, P.E., CH2M Hill on behalf of IPSC	08/24/04	DAQ	3875-4121
Technical Memorandum IPP: Analysis of Cumulative PM10 Increment Consumption Modeling Approach	08/25/04	DAQ	4122-4149
Letter to Reed T. Searle, General Manager, IPA, from Richard W. Sprott, Executive Secretary, Utah Air Quality Board	08/25/04	DAQ	4150
Letter to Rick Sprott, Executive Secretary, DAQ, from Stephen C. Sands, II, P.E., Project Manager, CH2M Hill re IPP Unit 3 Permit Provision governing excess emissions	08/25/04	DAQ	4151-4196

Record Description	Date	Added to Record By	Record page [IPSC]
Letter Milka Radulovic, DAQ, UDEQ from Stephen C. Sands II, Project Manager, CH2M Hill re IPP3: Economic Report and References for Impacts to Soils and Vegetation	09/14/04	DAQ	4197-4226
Letter to Milka Radulovic, DAQ, UDEQ from Stephen C. Sands II, Project Manager, CH2M Hill re IPP Response to Public Comments on Unit 3 Impacts to Soils and Vegetation	09/22/04	DAQ	4227-4288
Email to R Ruby and R Dolsen, from Stephen Sands, CH2M Hill re IPP Mobile Source Emission Rates	10/07/04	DAQ	4289
Memorandum to IPSC File (N327010) from Milka Radulovic, Environmental Engineer, through Rusty Ruby, NSR Section Manager re Response to Comments received on IPSC Intent to Approve number DAQE-IN327010-04	10/14/04	DAQ	4290-4330
Letter to George W. Cross, IPSC from Richard W. Sprott, Executive Secretary, Utah Air Quality Board re Approval Order: PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station, Millard County, Utah CDS-A, ATT, NSPS, Hap's, MACT, Title IV, Title V Major. Project Code: N0327-010	10/15/04	DAQ	4331-4345
Memorandum to IPSC File (N327010) through Cheryl Heying, Manager, Planning Branch, Brock LeBaron, Manager, Technical Analysis Section from Tom Orth, Air Quality Modeler re Technical Analysis' response to comments received on IPSC's Intent to Approve number DAQE-IN327010-04	10/15/04	DAQ	4346-4360
Letter to Richard Sprott, Executive Secretary, Air Quality Board, from George W. Cross, President & Chief Operations Officer & Responsible Official re Request for Agency Action - Appeal of IPSC Approval Order DAQE-AN032010-04	11/12/04	DAQ	4361-4367
Request for Agency Action - Western Resource Advocates	11/15/04	DAQ	4368-4384
Statement of Standing and Petition to Intervene - Western Resource Advocates	11/15/04	DAQ	4385-4397
Affidavit of Ray Bloxham	11/10/04	DAQ	4398-4402
Affidavit of Stephen Trimble	11/15/04	DAQ	4403-4408

Record Description	Date	Added to Record By	Record page [IPSC]
Affidavit of Brian Cass	11/10/04	DAQ	4409-4413
Letter to Rick Sprott, DAQ, from Reed Searle, General Manager, IPA re IPP Unit's PSD Permit-Approval Order-Title V Permit Informal Consultation under Section 7, Endangered Species Act (ESA)	12/17/04	DAQ	4414-4423
Intermountain Power Unit 3: Review of Past and Current Environmental Conditions in the Project Area prepared for Hogan & Hartson LLP by ERM	12/04	DAQ	4424-4435
EPA Fact Sheet: Prevention of Significant Deterioration: Proposed Rule to Address Emissions of Nitrogen Oxides in Clean Air Areas	03/08/05	DAQ	4436-4438
Letter to Richard Sprott, Executive Secretary, DAQ, DEQ, from George W. Cross, President and Chief Operations Officer and Responsible Official, IPSC re Fugitive Dust Control Plan for Intermountain Generating Station Unit 3 Under Approval Order DAQE-AN0327010-04	04/28/05	DAQ	4439-4451
Order Regarding Parties' Joint Stipulation for Disposition of This Contested Case, Parties' Joint Stipulation for Disposition of This Contested Case with Appendix A Approval Order incorporating the terms of the Joint Stipulation approved by Order of the Air Quality Board on September 7, 2005	09/08/05	DAQ	4452-4472
Letter to Rick Sprott, DAQ, from Douglas O. Hunter, Chairman, Unit 3 Development Committee re Engineering and Procurement of IPSC Unit 3 Boiler-Supercritical	08/04/06	DAQ	4473-4477
Letter to Doug Hunter, Chairman, Unit 3 Development Committee, from Richard W. Sprott, Executive Secretary, Air Quality Board, re Equivalency Determination for the IPSC Unit 3 Pulverized Coal (PC) Fired Boiler	08/17/06	DAQ	4478-4483
Letter to Rick Sprott, Executive Director, DAQ, from Joro Walker for Utah Chapter of the Sierra Club and Grand Canyon Trust re DAQ approval of the IPSC request to change Unit 3 boiler technology	11/13/06	DAQ	4484-4485
Email to Blaine Rawson, Fred Nelson, Chris Stephens... from Joro Walker, Western Resources re IPSC Unit 3 Project changes	11/14/06	DAQ	4486-4487

Record Description	Date	Added to Record By	Record page [IPSC]
Letter to Joro Walker, Western Resource Advocates from Christian C. Stephens and Paul M. McConkie, Assistant Attorneys General re WRA Letter Requesting Public Comment on DAQ's Approval or IPSC's Request to Change Unit 3 Boiler Technology	11/15/06	DAQ	4488-4490
Request for Agency Action [First Amended Request for Agency Action or, in the Alternative, Second Request for Agency Action]	11/15/06	DAQ	4491-4512
IPSC's Opposition/Response to Sierra Club's Amended Request for Agency Action	01/02/07	DAQ	4513-4528
Executive Secretary's Response to Sierra Club's Amended Request for Agency Action	01/04/07	DAQ	4529-4544

CERTIFICATE OF SERVICE

I hereby certify that on this 6th day of February, 2007, I caused a copy of the foregoing EXECUTIVE SECRETARY'S IDENTIFICATION OF THE ADMINISTRATIVE RECORD to be emailed or mailed by United States Mail, postage prepaid, to the following:

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EXHIBIT 3

IPP Response to Public Comments Received by UDAQ on the Draft Approval Order IPP Unit 3

August 2004

Comment 4: UDAQ and IPSC should have considered a supercritical pulverized coal boiler for the new unit

Comment 4.1: UDAQ and IPSC should have also considered the construction of a supercritical pulverized coal boiler, rather than the planned subcritical pulverized coal boiler. Supercritical boilers are up to 7% or more efficient than subcritical boilers. Thus, supercritical boilers use less fuel and emit less carbon dioxide emissions. Further, such supercritical boilers achieve up to 17% lower emission rates of carbon monoxide (CO), nitrogen oxides (NO_x) and sulfur oxides (SO_x), as well as up to 15% lower PM emission rates. For example, Steag has recently submitted a PSD permit application to the U.S. EPA for a supercritical boiler that would achieve an emission limit for SO_2 of .06 lbs/MMbtu on a 30 day rolling average (attached). This SO_2 emission limit is significantly lower than that being proposed by IPP and can be attributed at least in part to the employment of a supercritical boiler. Xcel Energy is also considering the construction of a supercritical boiler for new proposed unit at its Comanche plant in Pueblo, Colorado. Thus, UDAQ and IPSC should have evaluated the installation of a supercritical boiler at IPP Unit 3 as an inherently lower emitting process as part of its BACT determination.

IPP Response 4.1:

- *In the conceptual design phase of the project, IPSC evaluated supercritical boilers and concluded an additional subcritical boiler was more appropriate based on safety, environmental, and economic considerations.*
- *The existing units are subcritical and will share a common control room.*
- *Having two different operating cycles could pose problems with safe operation of the units if operators switch from one unit to the other.*
- *If operators are dedicated to the new unit only, additional staff will be required.*
- *Maintenance practices will differ due to different equipment and materials.*
- *The steam cycle for the subcritical boiler as proposed will be only 2 to 3 percent higher in heat rate than supercritical cycle.*
- *The statement that supercritical boilers are up to 7 percent or more efficient than subcritical boilers is inaccurate and is based on a comparison of old subcritical cycles with newer supercritical cycles.*
- *When new subcritical units use higher steam conditions and the 8th feedwater heater, the heat rate improves to approximately 2 to 3 percent of the heat rate achieved by a supercritical cycle.*
- *Units 1 and 2 are also advanced cycle (8th feedwater heater) designs that have demonstrated reliable performance over the past 20 years.*
- *The slight difference in heat rate is not sufficient to warrant a different cycle for Unit 3.*
- *With the low proposed emission limits for SO_2, NO_x, and particulates, the actual reduction in tons per year does not warrant the increase in capital costs, safety, and equipment compatibility issues associated with a supercritical boiler.*
- *There now is one unit with the newer supercritical boiler design under construction in the U.S. It is at the Council Bluff's site for MidAmerica and it is scheduled for mid-2007 startup.*
- *There are reliability concerns with supercritical in favor of subcritical boiler designs.*

EXHIBIT 4

Memorandum

To: Intermountain Power Service Corporation (IPSC) File (N327010)

From: Milka Radulovic, Environmental Engineer

Through: Rusty Ruby, NSR Section Manager, R 10/14/04

Regg Olsen, Permitting Branch Manager RDO 10/14/04

Date: October 14, 2004

Re: Response to Comments received on IPSC Intent to Approve number DAQE- IN327010-04

On April 1, 2004, a public comment period began to solicit comments on Intent to Approve (ITA) Intermountain Power Service Corporation's (IPSC) addition of New Unit 3 at their existing Intermountain Power Plant (IPP), located in Delta, Millard County, Utah. The IPSC proposed an electricity-generating unit with a pulverized coal fired boiler to provide 950 MW gross (900 MW net nominal) of electrical power. At the Millard County Economic Development Director's request a public hearing was held on April 29, 2004. The public hearing found overwhelming support for the new unit from the local population, medical and educational community.

In accordance with public request, the comment period was extended by twenty one (21) days.

On June 3, 2004, an additional 30-day comment period was started, to address shortcomings in the previous public notice of April 1, 2004.

Numerous comments were received, both during the comment period and at the public hearing. All comments received during the two public comment periods and the public hearing are listed here, with the original comments being included as an attachment. Following each comment is the Utah Division of Air Quality's (UDAQ) response, along with any action taken by the Division in regards to the final Approval Order (AO).

Quoted items are taken verbatim from the original comment submission. If the comment was unclear, UDAQ attempted to explain the comment as understood by the Division.

UDAQ responded to the following comments:

Comments made during the public comment periods (PCP) from April 1 to May 21 and from June 3 to July 3, 2004, and the public hearing (PH) of April 29, 2004.

Comments by Utah Chapter Sierra Club, Wasatch Clean Air Coalition, Grand Canyon Trust, Rocky Mountain Office of Environmental Defense, Western Resource Advocates, and Clean Air Task Force of May 20, 2004 (UWG). Our responses to UWG comments of May 20, 2004 also provide, by reference, responses to UWG comments of April 14, 2003. On April 14, 2003, UWG submitted comments regarding the December 23, 2002 Notice of Intent (NOI) for the IPP Unit 3. However, the IPP Unit 3 project was not available for public comment until April 1, 2004. Nevertheless, UDAQ has considered these comments as well.

In other recent applications for coal-fired units, the permitting authorities have not requested the applicants include in their BACT analysis production processes different than the proposed one. These states are Kansas, Missouri, Montana, Wyoming, Kentucky, Wisconsin, Arkansas and West Virginia. Also, as mentioned previously, although not required, the applicant provided and we reviewed a detailed analysis of IGCC.

Comment #14

> "IPP failed to correctly address IGCC in the BACT analysis and the permit must be denied. A properly conducted BACT analysis shows IGCC is BACT for the IPP project." (UWG, p.8)

Response

UDAQ has reviewed this issue in light of the comment. As discussed in the response to Comment #12 above, UDAQ has concluded that IGCC has been properly addressed. Additionally, a revised top-down analysis, though not required, has been provided by IPP. This analysis shows that IGCC would not be appropriate for the IPP project.

Comment #15

> "UDAQ and IPSC should have considered a supercritical pulverized coal boiler for the new unit." (UWG, p.22)

Response

UDAQ has reviewed this issue in light of the comment. Based on all available information and the discussion above, UDAQ has concluded that supercritical pulverized coal boilers have been considered appropriately. Additionally, a top-down analysis including supercritical boiler technology, though not required, was provided. That analysis shows that supercritical boilers would not be appropriate for the IPP project. Also, supercritical boilers are no more effective than sate-of-the-art subcritical boilers in controlling emissions of regulated pollutants. At this point in time, the new emission limits for the IPP Unit 3 are the most stringent emission limits, that we are aware of, imposed by any permit, granted or pending, for a pulverized coal-fired boiler in the U.S.A.., whether subcritical or supercritical. For example, see the proposed emission limits for supercritical boilers in three recently issued or pending permits: MidAmerican Energy, Longview Power, and Elm Road.

The paper by Bartolomei, referenced in the comment, provides information on expected rates and not on emission limits. In addition, the statements by Bartolomei are opinions and not commercial offers backed-up by guaranties. Thus, they are not properly part of a BACT analysis except for general information.

The commenter points out the proposed emission limits for the planned Steag facility to reinforce their comment. We have reviewed the PSD permit **application** for Steag Power's Desert Rock Energy facility and there are some issues that we point out regarding this application. First, this is only an application; the permitting process is in a very early stage. Obviously, the existence of a permit application, with no issued permit and no facility, does not provide any information that is informative as to technical feasibility and achievability of a particular emission limit. Second, the application seems to be substantially inconsistent regarding the sulfur dioxide emission limits. For example, we find the following statement on page 4-11: "Steag is proposing to limit SO_2

EXHIBIT 5

UAMPS
UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS
2825 E Cottonwood Parkway
Suite 200
Salt Lake City, Utah 84121-7077
Phone: 801-566-3938
Toll Free: 800-872-5961
Fax. 801-561-2687

N0327-016

UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY
AUG - 7 2006
DIVISION OF AIR QUALITY

August 4, 2006

Mr. Rick Sprott
Utah Division of Air Quality
150 North 1950 West
Salt Lake City, Utah 84114

Re: Engineering and Procurement of IPSC Unit 3 Boiler-Supercritical

Dear Mr. Sprott:

We are writing concerning our intent to use a supercritical boiler design for the Intermountain Power Service Corporation (IPSC) Unit # 3 to be located near Delta, Utah. The IPSC Unit 3 Development Committee is preparing bids for the engineering and procurement phase of construction. This letter is part of our efforts to keep the Division apprised of our construction status. As you recall, in December 2002, IPSC submitted a Notice of Intent (NOI) to permit and construct this nominal 950-gross megawatt (MW) (900-net MW) pulverized coal (PC) fired unit. An Approval Order (AO) for the construction of the proposed project was issued by the Utah Division of Air Quality (UDAQ) on October 15, 2004. The AO does not specify the specific type of PC-boiler the facility must use.

As we have proceeded with the highly complex process of developing the plant, we have concluded that a supercritical boiler design is more efficient and better for the environment, that it reflects the latest engineering and market developments for PC facilities, and that it accommodates those who favored a supercritical boiler design in their comments regarding the AO. We believe that use of a supercritical boiler design is consistent with the AO. We are preparing to order this equipment, and want to notify you prior to entering into an Engineering, Procurement and Construction (EPC) contract. We do not believe that any update of the AO is necessary in response to this notification letter. The following information is submitted to explain our conclusion that a supercritical design is consistent with the AO.

What is the difference between a Subcritical and Supercritical Boiler Design?

A supercritical boiler is functionally equivalent to a subcritical boiler except that, in order to create greater efficiencies, a supercritical boiler generates steam at higher pressures and

temperatures. This makes supercritical boiler-turbine technology more efficient in converting heat from the burning coal to driving the steam turbine generator. In all other respects, a supercritical boiler is equivalent to a subcritical design.

In a typical fossil-fuel boiler, water-containing tubes line the inside of the furnace walls. Fuel is ignited and burned as it enters the furnace. The burning fuel releases thermal energy, which is absorbed by the water in the tubes. As the temperature of the water rises, the water begins to boil. Water and steam are separated in a boiler drum and the steam, after additional heating in the boiler, is piped from the boiler to the steam turbine.

In a supercritical boiler design, the operating pressure exceeds the critical point of water. The critical point of water is at a pressure of 3,208 pounds per square inch absolute (psia); a point above which distinct liquid and vapor (steam) phases no longer exist, and the water is in a supercritical fluid state. Water and steam separation occurs without a boiler drum and the superheated fluid is sent directly to the steam turbine. A plant operating at this high pressure is more energy efficient and is referred to as a supercritical unit. Other than the higher operating pressure and temperature of steam at the supercritical plant, the design features are equivalent to a subcritical unit.

The subcritical boiler design has a 2520 psig/1050°F/1050°F steam power cycle providing a net plant efficiency (HHV)1 of approximately 35.77 percent, while the supercritical boiler design typically has a 3500 psig/1050°F/1100°F steam power cycle providing a net plant efficiency (HHV) of approximately 36.75 percent. As a result, there is approximately a three percent improvement in heat rate between the two cycles, thereby increasing the power output of the steam turbine-generator for the same coal burned in the boiler. Alternatively, a supercritical boiler can produce the same level of power output using a lesser amount of coal.

Using a supercritical boiler will not increase the heat input rate or the emission limits included in the AO. It will not increase coal consumption limits or alter the fuel types. The supercritical boiler will have the same maximum gross heat input of 9,050 million British Thermal Units per hour (MMbtu/hr), as listed in the AO. No changes will occur to the stack parameters. The stack will be designed with the same exit velocity and temperature as modeled. Therefore no additional dispersion modeling should be required since the emissions are the same and the stack parameters will not change.

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[1] Net Plant Efficiency (HHV) is defined as the net electrical output of the plant divided by the higher heating value fuel consumption of the plant.

Will emissions remain stable or decrease with a supercritical boiler design?

Unit emissions, coal feed rate and heat input to the boiler will in all cases remain at or below the levels specified in the AO. See Exhibit 1 for a comparison of the sub critical design and supercritical boiler design.

Installation of a supercritical boiler will result in a net decrease in emissions as measured in lbs/MWh. Also, as with the subcritical boiler design, the supercritical boiler will use a baghouse for particulate emissions control, a wet limestone scrubber for control of sulfur dioxide and acid gas emissions; and Low NOx Burners/Over-Fire-Air and Selective Catalytic Reduction for NOx emissions control. The design of the emissions control equipment will be the same as for the subcritical design.

Are BACT-Level Emission Controls the same for Supercritical and Subcritical Boilers?

The BACT analysis completed for IPP3 showed that BACT-Level emission controls were the same for both designs. The same list of potential control technologies were considered for each pollutant in the BACT analyses for supercritical units as was used in the IPSC Unit 3 PC BACT analysis. The control effectiveness of the technologies for each pollutant was also the same. No distinction was made between the supercritical PC boiler design of these units and the subcritical PC design of other units when consulting the EPA's RACT/BACT/LAER Clearinghouse (RBLC) and recently approved PSD permits to assist in selecting BACT for the projects. The primary difference between the BACT analysis outcomes for the various units was that a wet limestone FGD process was selected for IPSC Unit 3 with an emission limit of 0.09 Lb/MMBtu on a 30 day rolling average based on burning western bituminous coal versus some of the other units which each selected a dry lime FGD process with an emission limit of 0.10 Lb/MMBtu based on burning subbituminous Powder River Basin (PRB) coal. Low-NOx burners with Selective Catalytic Reduction were selected as BACT for NOx control and fabric filters were selected as BACT for Particulate Matter (PM) control.

The BACT process evaluates pollution control equipment in order to determine a proper BACT emission rate; it does not evaluate the boiler design. UDEQ (and EPA) have repeatedly confirmed this. Whether the boiler is subcritical or supercritical design, the BACT process evaluates the same pollution control equipment. The results of the IPP3 BACT analysis showed that there is no difference in pollution control equipment or BACT emission limits between a subcritical and a supercritical boiler.

Is it necessary to update the existing AO?

We believe it is not necessary to update the AO. When UDAQ issued its AO, DAQE-AN0327010-04, for the new IPSC Unit 3 on October 15, 2004, the AO approved installation of a "Dry-bottom Pulverized Coal Fired Boiler for base load operation with Overfire Air Ports

System" or its equivalent (the NOI described the unit as "an indoor type, subcritical, PC-fired boiler designed for base load operation" and then the AO imposed permit conditions to limit emissions). See AO at Condition #7. The AO does not specify the type of boiler as subcritical or supercritical. The AO only species the maximum heat input rate, 9050 x 106 Btu/hr, and the coal consumption limits, 3,541,248 tons of coal burned per rolling 12-month period. See AO Condition #7 and Condition #14. In addition, the AO limits the fuel to either "bituminous or blend of bituminous and up to thirty percent subbituminous coals." See AO at Condition #19. Selection of a supercritical boiler will not affect or exceed the heat input rate, the consumption limits or the types of fuel specified in the AO. Selection of a supercritical boiler does not constitute a major modification because it does not constitute a physical change or change in operation of an existing source and does not result in a significant emissions increase. Indeed, as noted, the emission limits will be the same for a subcritical or supercritical design. Selection of a supercritical boiler will not affect or exceed the heat input rate, the consumption limits or the types of fuel specified in the AO. In fact, the supercritical boiler will have the same coal consumption rate and the same gross heat input rate allowed in the AO, but it will be more efficient. Accordingly, a supercritical boiler design is consistent with the AO, and was the preferred boiler design of some commentrs during the public comment process for the AO. Therefore, the use of a supercritical boiler is consistent with the AO. This letter is notification to you of our continuing construction efforts, and in the near future the IPSC Unit 3 Development Committee intends to enter into an EPC contract for a supercritical boiler.

If you have any questions or need additional information, please contact me at your earliest convenience. Thank you for your consideration of this matter.

Sincerely,

Douglas O. Hunter
Chairman, Unit 3 Development Committee

Enclosure

Exhibit 1
IPP Unit 3 Project
Unit 3 Boiler Emissions Comparison

	Permit Basis Subcritical Design	Super Critical Boiler Design
Coal Feed Rate (tons/hr)	404	404
Heat Input to Boiler (MMBtu/hr)	9,050	9,050
Annual Capacity Factor (%/yr)	100	100
NOx		
NOx Boiler Emissions (lb/MMBtu)	0.35	0.35
NOx Stack Emissions (lb/MMBtu)	0.070	0.070
SO_2		
SO_2 Boiler Emissions (lb/MMBtu)	1.34	1.34
SO_2 Stack Emissions (lb/MMBtu)	0.090	0.090
CO		
CO Emission Factor (lb/MMBtu)	0.154	0.154
Filterable PM		
Filterable PM Stack Emissions (lb/MMBtu)	0.013	0.013
Filterable PM_{10}		
Filterable PM_{10} Stack Emissions (lb/MMBtu)	0.012	0.012
VOC		
VOC Emissions (lb/MMBtu)	0.00268	0.00268
Sulfuric Acid Mist		
H_2SO_4 Stack Emissions (lb/MMBtu)	0.00439	0.00439
Ammonium Sulfate		
$(NH_4)_2SO_4$ Stack Emissions (lb/MMBtu)	0.00030	0 00030
Hydrogen Chloride		
HCl Stack Emissions (lb/MMBtu)	0.00421	0.00421
HCl Stack Emissions (lb/hr)	38.13000	38.13000
Hydrogen Fluoride		
HF Stack Emissions (lb/MMBtu)	0.001	0.001
Stack Conditions		
Stack Exit Flow (acfm)	3,244,126	3,244,126
Stack Exit Diameter (feet)	31 85	31.85
Stack Exit Temperature (degF)	135	135

EXHIBIT 6

State of Utah

Department of
Environmental Quality

Dianne R. Nielson, Ph.D.
Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

DAQE-GN0327016-06

August 17, 2006

Project fee ID:N0327-016

Doug Hunter
Chairman, Unit 3 Development Committee
2825 E. Cottonwood Parkway
Salt Lake City, Utah 84121-7077

Dear Mr. Hunter

Re: Equivalency Determination for the Intermountain Power Service Corporation (IPSC) Unit 3 Pulverized Coal (PC) Fired Boiler

This letter is in response to the letter submitted August 7, 2006, concerning the installation of the IPSC Unit 3 PC boiler at the Intermountain Power Plant, near Delta, Utah . Utah Division of Air Quality agrees, that in accordance with Condition 7 of the Approval Order number DAQE-AN0327010-04*, a supercritical PC boiler is equivalent to the permitted unit.

The supercritical boiler shall operate under the conditions listed in Approval Order number DAQE-AN0327010-04*.

Please direct any technical questions you may have on this letter to Ms. Milka Radulovic. She may be reached at (801) 536-4232.

Sincerely,

Richard W. Sprott, Executive Secretary
Utah Air Quality Board

RWS:MR:kw

150 North 1950 West • PO Box 144820 • Salt Lake City, UT 84114-4820 • phone (801) 536-4000 • fax (801) 536-4099
T.D.D. (801) 536-4414 • *www.deq.utah.gov*

EXHIBIT 7

Joro Walker, USB #6676
David Becker USB #11037
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Salt Lake City, Utah 84111
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Attorneys for Utah Chapter of the Sierra Club
and Grand Canyon Trust

UTAH DEPARTMENT OF
ENVIRONMENTAL QUALITY
NOV 16 2006
DIVISION OF AIR QUALITY

BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station, Millard County, Utah Project Code: N0327-010 DAQE-AN0327010-04	:	REQUEST FOR AGENCY ACTION

FIRST AMENDED REQUEST FOR AGENCY ACTION
OR, IN THE ALTERNATIVE, SECOND REQUEST FOR AGENCY ACTION[1]

Pursuant to Utah Administrative Code R307-103-3(1) and Utah Code § 63-46b-3(3), the Utah Chapter of the Sierra Club and Grand Canyon Trust hereby file their Request for Agency Action with Richard W. Sprott, Executive Secretary of the Utah Air Quality Board. The Sierra Club and Grand Canyon Trust seek review of the October 15, 2004 decision by the Utah Division of Air Quality and the Executive Secretary (collectively "UDAQ") to issue an Approval Order (AO) granting a Prevention of Significant Deterioration (PSD) permit to Intermountain Power Service Corporation (IPSC) to construct and operate an additional 950 megawatt (MW) coal-fired power plant Unit #3 at the Intermountain Power Plant in Millard County, Utah (DAQE-AN0327010-04)(Project Code: N0327-010). Pursuant to Utah Admin. Code R307-103-3(2), R307-103-6(2)(c), and R307-103-3, the Sierra Club and Grand Canyon Trust submit with

[1] Sierra Club and Grand Canyon Trust request that they be allowed to amend their November 15, 2004 Request for Agency Action with the additions indicated herein. In the alternative, the conservation groups file this pleading as a Second Request for Agency Action as an independent Second Request for Agency Action **without** withdrawing their November 15, 2005 Request for Agency Action. A Statement of Standing/Petition to Intervene in Support of Second Request for Agency Action is attached.

2. UDAQ Failed to Consider Adequately a Supercritical PC Boiler in its BACT Determination and Failed to Require Installation of this Technology for IPP Unit 3.

For essentially the same reasons provided above, UDAQ's consideration of supercritical PC boiler technology is legally inadequate and therefore the AO is fatally flawed. Supercritical boilers are up to 7% or more efficient than subcritical boilers. As a result, they use less fuel and emit less carbon dioxide. Further, such supercritical boilers achieve up to 17% lower emission rates of carbon monoxide (CO), nitrogen oxides (NOx) and sulfur oxides (SOx), as well as up to 15% lower PM emission rates.

Yet, UDAQ argues that it need not analyze this technology as part of its BACT determination. Response to Comments at 8, # 15. The agency's conclusion is flawed. Consideration of inherently lower emitting power production processes and techniques such as supercritical boiler is required by Utah Admin. Code R307-101-2, the state regulation defining BACT. Legislative history, EPA guidance, the actions of regulators in other states, and other relevant considerations additionally confirm that because consideration of the process design is a necessary part of the BACT analysis, thorough evaluation of this technology is mandated.

To the extent that UDAQ suggests that it has now revised its review of supercritical boiler technology for the purposes of BACT analysis, Response to Comments at 8, #15, this revision is inadequate for the purposes of state and federal law. For example, this review was not subject to public notice and comment. Moreover, because the Sierra Club and Grand Canyon Trust have not had the opportunity to assess the revised analysis, they reserve the right to challenge its content. Because UDAQ states that this revised analysis determined that a supercritical boiler is not appropriate for IPP Unit 3, the conclusions of the evaluation are incorrect.

Rather, evaluation of supercritical boilers is required, as this technology, although inferior to IGCC, is an available technology, is technically feasible for the IPP project, and is a better ranked control technology than that currently proposed for Unit 3. In sum, UDAQ is required to consider supercritical boiler technology exhaustively as part of its BACT analysis. The revised analysis errs in that it has not been subject to public comment and it concludes this technology is not appropriate for the IPP Unit 3. As a result, UDAQ has failed its statutory and regulatory duties to examine supercritical boiler technology adequately and to require the IPSC to utilize a supercritical boiler pursuant to a BACT determination. Until UDAQ takes these steps, the AO is illegal and should be rescinded and/or remanded to the agency for proper BACT analysis.

3. UDAQ Erroneously Failed to Address Carbon Dioxide and Other Greenhouse Gas Emissions.

In approving the construction and operation of IPP Unit 3, UDAQ did not address or set limits on carbon dioxide (CO_2) or other greenhouse gas emissions from the new unit. Typically, coal-fired boilers emit significant greenhouse gases. Yet, UDAQ declined to address greenhouse

EXHIBIT 8

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Attorneys for Utah Chapter of the Sierra Club

BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station, Millard County, Utah Project Code: N0327-010 DAQE-AN0327010-04	: : : : : :	DECLARATION OF WALTER KOUCKY

I, Walter Koucky, declare as follows:

1. The facts set forth in this declaration are based upon my personal knowledge. If called as a witness, I could and would testify to these facts. As to those matters which reflect an opinion, they reflect my professional opinion and judgment on the matter.

2. I am an adult citizen of the United States and currently reside in Cincinnati, Ohio.

3. I have worked in the field of air pollution control permitting since 1984. During that time, I have worked on permits for individual facilities. I have also supported U.S. Environmental Protection Agency (EPA) national efforts in both regulatory development and national enforcement initiatives. Attached is

my curriculum vitae that gives the specifics of my education and as well as my technical work involving New Source Review and other permit programs.

4. During my career, I have also developed expertise in the calculation of emissions, New Source Review permitting and evaluation of air pollution controls. Attached is my curriculum vitae that gives the specifics of my technical work in this field.

5. In its August 4, 2006 letter to Rick Sprott, Utah Division of Air Quality, the Utah Associated Municipal Power Systems (UAMPS) compares a supercritical pulverized coal boiler design to a subcritical pulverized coal boiler design. In doing so, UAMPS states: "Installation of a supercritical boiler will result in a net decrease in emissions as measured in lbs/MWh." AR IPSC 4475. I generally agree with this statement. Because a supercritical boiler is more thermally efficient, this technology should produces lower emissions of criteria pollutants and carbon-dioxide per megawatt generated when compared to a subcritical .boiler in similar operation.

6. The change from a subcritical boiler to a supercritical boiler will affect emissions of criteria pollutants as well as carbon dioxide from Unit 3. Although the overall higher thermal efficiency is expected to reduce emissions of criteria pollutants, this assumption is not guaranteed in all situations. Emissions from all operating modes and all supporting systems must be fully investigated on a site specific basis considering specific fuels, equipment designs and environmental impacts.

7. EPA demonstrated in a July 2006 Final Report entitled "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle

and Pulverized Coal Technologies,"[1] that supercritical PC technology results in lower expected emissions expressed in pounds per megawatt hour. Ultra-supercritical boiler designs result in even lower expected emissions and higher thermal efficiencies. As the selected boiler technology is a component of the BACT [best available control technology] determination, the State of Utah is voiding the BACT determination by selecting a boiler different technology. Before allowing a modification to the permitted technology, the State of Utah must determine if ultra-supercritical pulverized coal technology or another technology is BACT.

8. UAMPS also states that: "The BACT [best available control technology] analysis completed for IPP3 [Unit 3] showed that BACT-Level emission controls were the same for" supercritical and subcritical boilers. AR IPSC 4475. This statement is wrong insofar as proper BACT analysis would show substantially reduced emission controls for a supercritical boiler. This statement is inconsistent with the statement that "Installation of a supercritical boiler will result in a net decrease in emissions as measured in lbs/MWh." AR IPSC 4475. This is also inconsistent with the requirement that BACT be the "maximum degree of reduction of each pollutant subject to the Act" [UAC R307-101-2]. The existing BACT analysis is clearly flawed in that it failed to require a technology that resulted in lower hourly emissions.

9. A proper BACT analysis considers technological feasibility and impacts, including economic, together with control effectiveness to evaluate the most

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[1] This report is found at http://www.epa.gov/air/caaac/coaltech/2007_01_epaigcc.pdf and portions are attached to this sworn statement.

effective control options and determine emission limitations for a project. The current proposed technology change, from a subcritical to a supercritical boiler design, demonstrates that the supercritical technology is both technically feasible and not an excessive economic burden. As described above in Comment #8, the supercritical boiler has lower hourly emissions. This demonstrates that the previous BACT analysis was flawed in not requiring lower hourly emissions rates. Rather than allowing increased generation for the Intermountain 3 project, the State of Utah should correct the errant BACT determination and require more stringent emissions limitations for this project.

I declare under penalty of perjury that the foregoing is true and correct and that this declaration was executed on February 26, 2007, in Cincinnati, Ohio.

Walter F. Koucky

United States Environmental Protection Agency

EPA-430/R-06/006
July 2006

Final Report

Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies

Section 1 Process Design

Section 1 presents the design criteria and methodologies used in evaluating various processes and technologies discussed in this report.

1.1 Introduction

The U.S. Environmental Protection Agency (EPA) sponsored this study to evaluate and compare environmental impacts and costs of integrated gasification combined cycle (IGCC) and pulverized coal (PC) power plants. These estimated impacts and costs for the technologies will assist various government agencies to better understand the potential effects of rulemaking and regulatory actions on application of the technologies in practical, real-world conditions.

Results are based upon information collected in one of two ways. First, in-house Nexant software, experience with similar evaluations, and literature were used to estimate performance and costs of the two technologies. Second, equipment and process suppliers were contacted for updated information specific to the environmental control aspects of the plants. The suppliers' data were used to refine the first estimates and improve the performance and cost estimates of the environmental controls. Seeking new data from gasification technology developers was not within the scope of this report; it was judged that sufficient published and in-house data was available to assess gasification technology performance and cost.

1.2 Design Basis

The study examines five power generation technologies and three different coals. All the modeled power plants are sized for a net power generation of 500 MW. They are configured with equipment and processes that are judged available for deployment in power generation plants in the 2010 time period. The modeled plants include the following design features:

- IGCC plants with steam conditions of 1,800 psig and 1,000/1,000 °F. The coal-water slurry feed type of gasifier represented by GE Energy (ex-ChevronTexaco) is used with two coals, and a solid feed gasifier such as Shell gasification is used with lignite.

- PC plants with subcritical steam conditions of 2,400 psig and 1,000/1,000°F single reheat.

- PC plants with supercritical steam conditions of 3,500 psig and 1,050/1,050 °F double reheat.

- PC plants with ultra-supercritical steam conditions of 4,500 psig and 1,100/1,100 °F double reheat.

Exhibit 3-13, Subcritical Pulverized Coal Plant Environmental Impacts

Subcritical PC	Bituminous			Subbituminous			Lignite		
Air Pollutants	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu	Ppmvd @15% O_2	lb/MWh	lb/MMBtu
NO_X (NO_2) [1]	14	0.528	0.06	15	0.543	0.06	20	0.568	0.06
SO_2 [1]	15	0.757	0.086	11	0.589	0.065	10	0.814	0.086
CO [2]	39	0.880	0.10	40	0.906	0.10	55	0.947	0.10
Volatile Organic Compounds[2]		0.021	0.0024		0.025	0.0027		0.026	0.0027
Particulate Matter (overall) [1]		0.106	0.012		0.109	0.012		0.114	0.012
Particulate Matter (PM_{10}) [1]		0.106	0.012		0.109	0.012		0.114	0.012
Lead (Pb) [2]		$3.40x10^{-5}$ to $18x10^{-5}$	$3.86.x10^{-6}$ to $20x10^{-6}$		$18.1x10^{-5}$ to $23x0^{-5}$	$20x10^{-6}$ to $25.6x10^{-6}$		$18.9x10^{-5}$ to $24x10^{-5}$	$20x10^{-6}$ to $25.6x10^{-6}$
Mercury		$6.69x10^{-6}$	$0.76x10^{-6}$		$3.80x10^{-6}$	$0.42x10^{-6}$		$6.9x10^{-6}$	$0.73x10^{-6}$
Acid Mist		0.088	0.010		0.018	0.002		0.038	0.004
Other Environmental Impacts		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu
CO_2 [1]		1,777	202		1,893	209		1,998	211
Solid Waste (ash/FGD waste)		176	20		73	8		331	35
Raw Water Use		9,260	1,050		9,520	1,050		9,960	1,050
Sulfur Removal, %	98			87			95.8		
Particulates, Removal, %	99.8			99.7			99.9		

1. Calculated based on air permit data, discussions with equipment suppliers, literature, and process model software.
2. Estimated from review of air permit data.

Exhibit 3-14, Supercritical Pulverized Coal Plant Environmental Impacts

Supercritical PC	Bituminous			Subbituminous			Lignite		
Criteria Pollutants	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu
NO_X (NO_2) [1]	14	0.494	0.06	15	0.500	0.06	14	0.524	0.06
SO_2 [1]	15	0.709	0.086	11	0.541	0.065	7	0.751	0.086
CO [2]	39	0.824	0.10	40	0.832	0.10	39	0.873	0.10
Volatile Organic Compounds[2]		0.020	0.0024		0.023	0.0027		0.024	0.0027
Particulate Matter (overall) [1]		0.099	0.012		0.100	0.012		0.105	0.012
Particulate Matter (PM_{10}) [1]		0.099	0.012		0.100	0.012		0.105	0.012
Lead (Pb) [2]		3.18×10^{-5} to 17×10^{-5}	3.86×10^{-6} to 20×10^{-6}		16.6×10^{-5} to 21×10^{-5}	20×10^{-6} to 25.6×10^{-6}		17.5×10^{-5} to 22×10^{-5}	20×10^{-6} to 25.6×10^{-6}
Mercury		6.26×10^{-6}	0.76×10^{-6}		3.49×10^{-6}	0.42×10^{-6}		6.37×10^{-6}	0.73×10^{-6}
Acid Mist		0.082	0.010		0.017	0.002		0.035	0.004
Other Environmental Impacts		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu
CO_2 [1]		1,665	202		1,739	209		1,842	211
Solid Waste (ash/FGD wastes)		165	20		67	8		306	35
Raw Water Use		8,640	1,050		8,830	1,060		9,200	1,055
Sulfur Removal, %		98			87			95.8	
Particulates Removal, %		99.8			99.7			99.9	

1. Calculated based on air permit data, discussions with equipment suppliers, literature, and process model software.
2. Estimated from review of air permit data.

The high amount of ash (slag) in lignite makes it unsuitable for GE Energy's entrained flow gasifier, because heavy slagging of the radiant heat exchanger slows heat removal and exchange. Also, the need for high ash content slurry to be removed from the bottom of the gasifier which retains significant heat energy is another major source of heat loss. These two factors have significant impact on the thermal efficiency of the gasifier and overall IGCC plant. Although the GE Energy gasifier can handle high moisture coal, the efficiency loss from the ash content of lignite is significant enough to make it unattractive.

The Shell gasifier has a refractory-lined water wall for syngas heat removal which can handle high loading of ash and still be effective in heat transfer. There is no significant loss in efficiency in Shell gasifier.

Greater details of energy and material balances for the IGCC plants are included in Appendix C of this report.

Exhibits 3-4, 3-5, and 3-6 present summary performance data for the PC units and the three coals.

Exhibit 3-4 Subcritical Pulverized Coal Unit Performance Estimates

Subcritical PC	Bituminous	Subbituminous	Lignite
Net Thermal Efficiency, % HHV	35.9	34.8	33.1
Net Heat Rate, Btu/kWh (HHV)	9,500	9,800	10,300
Gross Power, MW	540	541	544
Internal Power, MW	40	41	44
Fuel required, lb/h	407,143	556,818	815,906
Net Power, MW	500	500	500

Exhibit 3-5 Supercritical Pulverized Coal Unit Performance Estimates

Supercritical PC	Bituminous	Subbituminous	Lignite
Net Thermal Efficiency, % HHV	38.3	37.9	35.9
Net Heat Rate, Btu/kWh (HHV)	8,900	9,000	9,500
Gross Power, MW	540	541	544
Internal Power, MW	40	41	44
Fuel required, lb/h	381,418	517,045	752,535
Net Power, MW	500	500	500

EXHIBIT 9

United States Environmental Protection Agency

EPA-430/R-06/006
July 2006

Final Report

Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies

Section 1 Process Design

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The study examines five power generation technologies and three different coals. All the modeled power plants are sized for a net power generation of 500 MW. They are configured with equipment and processes that are judged available for deployment in power generation plants in the 2010 time period. The modeled plants include the following design features:

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- PC plants with supercritical steam conditions of 3,500 psig and 1,050/1,050 °F double reheat.

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SO_2 [1]	15	0.757	0.086	11	0.589	0.065	10	0.814	0.086
CO [2]	39	0.880	0.10	40	0.906	0.10	55	0.947	0.10
Volatile Organic Compounds[2]		0.021	0.0024		0.025	0.0027		0.026	0.0027
Particulate Matter (overall) [1]		0.106	0.012		0.109	0.012		0.114	0.012
Particulate Matter (PM_{10}) [1]		0.106	0.012		0.109	0.012		0.114	0.012
Lead (Pb) [2]		$3.40x10^{-5}$ to $18x10^{-5}$	$3.86.x10^{-6}$ to $20x10^{-6}$		$18.1x10^{-5}$ to $23x0^{-5}$	$20x10^{-6}$ to $25.6x10^{-6}$		$18.9x10^{-5}$ to $24x10^{-5}$	$20x10^{-6}$ to $25.6x10^{-6}$
Mercury		$6.69x10^{-6}$	$0.76x10^{-6}$		$3.80x10^{-6}$	$0.42x10^{-6}$		$6.9x10^{-6}$	$0.73x10^{-6}$
Acid Mist		0.088	0.010		0.018	0.002		0.038	0.004
Other Environmental Impacts		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu
CO_2[1]		1,777	202		1,893	209		1,998	211
Solid Waste (ash/FGD waste)		176	20		73	8		331	35
Raw Water Use		9,260	1,050		9,520	1,050		9,960	1,050
Sulfur Removal, %	98			87			95.8		
Particulates, Removal, %	99.8			99.7			99.9		

1. Calculated based on air permit data, discussions with equipment suppliers, literature, and process model software.
2. Estimated from review of air permit data.

Exhibit 3-14, Supercritical Pulverized Coal Plant Environmental Impacts

Supercritical PC	Bituminous			Subbituminous			Lignite		
Criteria Pollutants	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu
NO_X (NO_2) [1]	14	0.494	0.06	15	0.500	0.06	14	0.524	0.06
SO_2 [1]	15	0.709	0.086	11	0.541	0.065	7	0.751	0.086
CO [2]	39	0.824	0.10	40	0.832	0.10	39	0.873	0.10
Volatile Organic Compounds[2]		0.020	0.0024		0.023	0.0027		0.024	0.0027
Particulate Matter (overall) [1]		0.099	0.012		0.100	0.012		0.105	0.012
Particulate Matter (PM_{10}) [1]		0.099	0.012		0.100	0.012		0.105	0.012
Lead (Pb) [2]		3.18×10^{-5} to 17×10^{-5}	3.86×10^{-6} to 20×10^{-6}		16.6×10^{-5} to 21×10^{-5}	20×10^{-6} to 25.6×10^{-6}		17.5×10^{-5} to 22×10^{-5}	20×10^{-6} to 25.6×10^{-6}
Mercury		6.26×10^{-6}	0.76×10^{-6}		3.49×10^{-6}	0.42×10^{-6}		6.37×10^{-6}	0.73×10^{-6}
Acid Mist		0.082	0.010		0.017	0.002		0.035	0.004
Other Environmental Impacts		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu
CO_2[1]		1,665	202		1,739	209		1,842	211
Solid Waste (ash/FGD wastes)		165	20		67	8		306	35
Raw Water Use		8,640	1,050		8,830	1,060		9,200	1,055
Sulfur Removal, %		98			87			95.8	
Particulates Removal, %		99.8			99.7			99.9	

1. Calculated based on air permit data, discussions with equipment suppliers, literature, and process model software.
2. Estimated from review of air permit data.

The high amount of ash (slag) in lignite makes it unsuitable for GE Energy's entrained flow gasifier, because heavy slagging of the radiant heat exchanger slows heat removal and exchange. Also, the need for high ash content slurry to be removed from the bottom of the gasifier which retains significant heat energy is another major source of heat loss. These two factors have significant impact on the thermal efficiency of the gasifier and overall IGCC plant. Although the GE Energy gasifier can handle high moisture coal, the efficiency loss from the ash content of lignite is significant enough to make it unattractive.

The Shell gasifier has a refractory-lined water wall for syngas heat removal which can handle high loading of ash and still be effective in heat transfer. There is no significant loss in efficiency in Shell gasifier.

Greater details of energy and material balances for the IGCC plants are included in Appendix C of this report.

Exhibits 3-4, 3-5, and 3-6 present summary performance data for the PC units and the three coals.

Exhibit 3-4 Subcritical Pulverized Coal Unit Performance Estimates

Subcritical PC	Bituminous	Subbituminous	Lignite
Net Thermal Efficiency, % HHV	35.9	34.8	33.1
Net Heat Rate, Btu/kWh (HHV)	9,500	9,800	10,300
Gross Power, MW	540	541	544
Internal Power, MW	40	41	44
Fuel required, lb/h	407,143	556,818	815,906
Net Power, MW	500	500	500

Exhibit 3-5 Supercritical Pulverized Coal Unit Performance Estimates

Supercritical PC	Bituminous	Subbituminous	Lignite
Net Thermal Efficiency, % HHV	38.3	37.9	35.9
Net Heat Rate, Btu/kWh (HHV)	8,900	9,000	9,500
Gross Power, MW	540	541	544
Internal Power, MW	40	41	44
Fuel required, lb/h	381,418	517,045	752,535
Net Power, MW	500	500	500

EXHIBIT 10

Joro Walker, USB #6676
David Becker USB #11037
WESTERN RESOURCE ADVOCATES
425 East 100 South Street
Salt Lake City, Utah 84111
Telephone: 801.487.9911
Fax: 801.486.4233
Attorneys for Utah Chapter of the Sierra Club

BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station, Millard County, Utah Project Code: N0327-010 DAQE-AN0327010-04	: : : : : : :	DECLARATION OF JOHN W. THOMPSON

I, John W. Thompson, declare as follows:

1. The facts set forth in this declaration are based upon my personal knowledge. If called as a witness, I could and would testify to these facts. As to those matters which reflect an opinion, they reflect my professional opinion and judgment on the matter.

2. I am an adult citizen of the United States and currently reside in Makanda, Illinois.

3. I have a B.S. in Chemical Engineering from the University of Illinois, and a Masters of Business Administration from the Olin School of Business at Washington University, St. Louis. My employer, the Clean Air Task Force (CATF), is a national nonprofit environmental organization dedicated to

restoring clean air through scientific research, public education, and legal advocacy. CATF is comprised of approximately twenty professionals with backgrounds in science, engineering, law, economics and public outreach headquartered in Boston and operates with a national focus on clean air issues. CATF is a leading environmental organization addressing air quality and atmospheric protection issues, and its work is widely respected in government and industry.

2. My work for CATF addresses several areas, including: preparing comments on coal-fueled power plant air permits, evaluating the economics and environmental characteristics of advanced coal technologies, educating the public about health impacts of power plant pollution, and working to develop state and federal rules on power plant emissions.

3. I frequently address conferences and workshops, particularly with respect to Integrated Gasification Combined Cycle (IGCC) and pulverized coal technology. In October 2003, I made a presentation at the U.S. Department of Energy's Twentieth Annual International Pittsburg Coal Conference, on the topic of "IGCC as LAER/BACT for the Production of Electricity from Coal." In April 2004, I made a presentation on IGCC environmental characteristics and economics to the Western Governors' Association Energy Summit. In June 2004, I addressed the Workshop on Gasification Technologies jointly sponsored by the U.S. Department of Energy, the National Association of Regulatory Commissioners, the Gasification Technologies Council, and the Southern States Energy Board. My presentation was titled "The BACT Analysis: Does IGCC Meet the Test?" In August 2004, I made a presentation

at the USEPA's Air Innovations Conference on the topic of IGCC. In October 2004, I made a presentation to the annual meeting of STAPPA/ALAPCO, a national association of state and tribal air directors, on the topic of IGCC and pulverized coal. My presentation was entitled "Integrated Gasification Combined Cycle (IGCC): Environmental Impacts and Policy Implications." In 2005, I addressed the Platts IGCC Symposium. My presentation was entitled "Integrated Gasification combined Cycle (IGCC) Environmental Performance." I also addressed a gasification workshop sponsored by the Gasification Technologies Council in April 2005 in Knoxville TN on IGCC. In November 2005, I spoke on IGCC and carbon sequestration topics at Infocast's IGCC Project Development and Finance Seminar and on "Public Perception of Gasification" at MIT's Carbon Sequestration Forum VI. In May 2006, I addressed Platts 2nd Annual IGCC Symposium on the topic of gasification performance. In February 2007, I addressed the USEPA's Advanced Coal Technologies Working Group on Advanced Coal technologies.

4. In my work with CATF, I have prepared and submitted comments on draft air permits to state regulators for both pulverized coal and IGCC plants. I have also testified as an expert witness on air permit appeals in Montana, Texas, and Wisconsin. I have also testified at a Colorado Public Utilities Commission proceeding also on pulverized coal plant hearings.

5. I was also co-chair the Technologies Subcommittee of the Western Governors Association's Clean Coal Task Force, where I reviewed the cost and performance of numerous current and future coal technologies.

6. Prior to joining the Task Force, I was Director of Clean Air Programs at the Illinois Environmental Council. For thirteen years, I was Executive Director of the Central States Education Center in Champaign, Illinois, an organization that developed advocacy and technical assistance programs on solid and hazardous waste issues. I began my career as a process development engineer with the Procter & Gamble CompanyAttached is my curriculum vitae that gives the specifics of my education and as well as my technical work involvingcoal issues.

7. In its August 4, 2006 letter to Rick Sprott, Utah Division of Air Quality, the Utah Associated Municipal Power Systems (UAMPS) compares a supercritical boiler design to a subcritical boiler design. In doing so, UAMPS states that "there is approximately a three percent improvement in heat rate between" the net plant efficiency (HHV) of a supercritical and a subcritical boiler. AR IPSC 4475. I disagree with this statement. This statement represents the increased efficiency for supercritical boilers over subcritical boilers as lower than the efficiency gains typical for supercritical boilers. I estimate the actual increase in efficiency to be more accurately represented in analysis conducted by the United States EPA.

8. In its July 2006 Final Report entitled "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies,"[1] EPA compared the efficiency of subcritical and supercritical boilers in terms of net thermal efficiency and heat rate, % HHV. EPA Report

[1] This report is found at http://www.epa.gov/air/caaac/coaltech/2007_01_epaigcc.pdf and portions are attached to this sworn statement.

at 3-3. In that comparison, the federal agency determined that a supercritical unit using bituminous coal has a net thermal efficiency of 38.3% and heat rate of 8900 Btu/kWh, and for subbituminous coal, a thermal efficiency of 37.9% and heat rate 9000 Btu/kWh. EPA Doc at 3-3.

9. Using UAMPS's figure of 35.77% for the efficiency of a subcritical boiler (with no coal type specified), and EPA's figures for a supercritical boiler, reveals a efficiency increase of about 7% for a supercritical boiler burning bituminous coal and a 6% efficiency for subbituminous coal. EPA Doc at 3-3; AR at IPSC4474.

10. Using EPA's figures for the pulverized coal boiler with subcritical steam cycle leads to a net efficiency increase of 6.7% and 8.9% from a subcritical to supercritical boiler using bituminous and subbituminous coal respectively. EPA Doc at 3-3; AR at IPSC4474.

11. Starting with a 950 megawatt facility, an increase in efficiency of 6.74%, keeping heat input the same, will mean that the facility will produce 1014 megawatts. An increased efficiency of 8.88%, keeping heat input the same, will mean that the facility will produce 1034 megawatts. The impact of various other efficiency rate increases on power output can be calculated by adding the additional megawatts generated due to efficiency (the percentage multiplied by 950 megawatts) to 950 megawatts.

12. A 950 megawatt facility is not equivalent to a 1014 or a 1034 megawatt facility. Equipment that produces 1014 or 1034 megawatts is not equivalent to equipment that produces 950 megawatts with the same heat input.

13. Even if the statement in the UAMPS letter that "there is approximately a three percent improvement in heat rate between" the net plant efficiency (HHV) of a supercritical and a subcritical boiler were true, a 3% increased efficiency, keeping heat input the same, will mean that the facility will produce 979 megawatts.

14. A 950 megawatt facility is not equivalent to a 979 megawatt facility. Equipment that produces 979 megawatts is not equivalent to equipment that produces 950 megawatts with the same heat input.

I declare under penalty of perjury that the foregoing is true and correct and that this declaration was executed on February 26, 2007, in Carbondale, Illinois.

John W. Thompson

United States Environmental Protection Agency

EPA-430/R-06/006
July 2006

Final Report

Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies

Section 1 Process Design

Section 1 presents the design criteria and methodologies used in evaluating various processes and technologies discussed in this report.

1.1 Introduction

The U.S. Environmental Protection Agency (EPA) sponsored this study to evaluate and compare environmental impacts and costs of integrated gasification combined cycle (IGCC) and pulverized coal (PC) power plants. These estimated impacts and costs for the technologies will assist various government agencies to better understand the potential effects of rulemaking and regulatory actions on application of the technologies in practical, real-world conditions.

Results are based upon information collected in one of two ways. First, in-house Nexant software, experience with similar evaluations, and literature were used to estimate performance and costs of the two technologies. Second, equipment and process suppliers were contacted for updated information specific to the environmental control aspects of the plants. The suppliers' data were used to refine the first estimates and improve the performance and cost estimates of the environmental controls. Seeking new data from gasification technology developers was not within the scope of this report; it was judged that sufficient published and in-house data was available to assess gasification technology performance and cost.

1.2 Design Basis

The study examines five power generation technologies and three different coals. All the modeled power plants are sized for a net power generation of 500 MW. They are configured with equipment and processes that are judged available for deployment in power generation plants in the 2010 time period. The modeled plants include the following design features:

- IGCC plants with steam conditions of 1,800 psig and 1,000/1,000 °F. The coal-water slurry feed type of gasifier represented by GE Energy (ex-ChevronTexaco) is used with two coals, and a solid feed gasifier such as Shell gasification is used with lignite.

- PC plants with subcritical steam conditions of 2,400 psig and 1,000/1,000°F single reheat.

- PC plants with supercritical steam conditions of 3,500 psig and 1,050/1,050 °F double reheat.

- PC plants with ultra-supercritical steam conditions of 4,500 psig and 1,100/1,100 °F double reheat.

Exhibit 3-13, Subcritical Pulverized Coal Plant Environmental Impacts

Subcritical PC	Bituminous			Subbituminous			Lignite		
Air Pollutants	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu	Ppmvd @15% O_2	lb/MWh	lb/MMBtu
NO_X (NO_2) [1]	14	0.528	0.06	15	0.543	0.06	20	0.568	0.06
SO_2 [1]	15	0.757	0.086	11	0.589	0.065	10	0.814	0.086
CO [2]	39	0.880	0.10	40	0.906	0.10	55	0.947	0.10
Volatile Organic Compounds[2]		0.021	0.0024		0.025	0.0027		0.026	0.0027
Particulate Matter (overall) [1]		0.106	0.012		0.109	0.012		0.114	0.012
Particulate Matter (PM_{10}) [1]		0.106	0.012		0.109	0.012		0.114	0.012
Lead (Pb) [2]		$3.40x10^{-5}$ to $18x10^{-5}$	$3.86.x10^{-6}$ to $20x10^{-6}$		$18.1x10^{-5}$ to $23x0^{-5}$	$20x10^{-6}$ to $25.6x10^{-6}$		$18.9x10^{-5}$ to $24x10^{-5}$	$20x10^{-6}$ to $25.6x10^{-6}$
Mercury		$6.69x10^{-6}$	$0.76x10^{-6}$		$3.80x10^{-6}$	$0.42x10^{-6}$		$6.9x10^{-6}$	$0.73x10^{-6}$
Acid Mist		0.088	0.010		0.018	0.002		0.038	0.004
Other Environmental Impacts		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu
CO_2 [1]		1,777	202		1,893	209		1,998	211
Solid Waste (ash/FGD waste)		176	20		73	8		331	35
Raw Water Use		9,260	1,050		9,520	1,050		9,960	1,050
Sulfur Removal, %	98			87			95.8		
Particulates, Removal, %	99.8			99.7			99.9		

1. Calculated based on air permit data, discussions with equipment suppliers, literature, and process model software.
2. Estimated from review of air permit data.

Exhibit 3-14, Supercritical Pulverized Coal Plant Environmental Impacts

Supercritical PC	Bituminous			Subbituminous			Lignite		
Criteria Pollutants	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu
NO_X (NO_2) [1]	14	0.494	0.06	15	0.500	0.06	14	0.524	0.06
SO_2 [1]	15	0.709	0.086	11	0.541	0.065	7	0.751	0.086
CO [2]	39	0.824	0.10	40	0.832	0.10	39	0.873	0.10
Volatile Organic Compounds[2]		0.020	0.0024		0.023	0.0027		0.024	0.0027
Particulate Matter (overall) [1]		0.099	0.012		0.100	0.012		0.105	0.012
Particulate Matter (PM_{10}) [1]		0.099	0.012		0.100	0.012		0.105	0.012
Lead (Pb) [2]		3.18×10^{-5} to 17×10^{-5}	3.86×10^{-6} to 20×10^{-6}		16.6×10^{-5} to 21×10^{-5}	20×10^{-6} to 25.6×10^{-6}		17.5×10^{-5} to 22×10^{-5}	20×10^{-6} to 25.6×10^{-6}
Mercury		6.26×10^{-6}	0.76×10^{-6}		3.49×10^{-6}	0.42×10^{-6}		6.37×10^{-6}	0.73×10^{-6}
Acid Mist		0.082	0.010		0.017	0.002		0.035	0.004
Other Environmental Impacts		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu
CO_2[1]		1,665	202		1,739	209		1,842	211
Solid Waste (ash/FGD wastes)		165	20		67	8		306	35
Raw Water Use		8,640	1,050		8,830	1,060		9,200	1,055
Sulfur Removal, %		98			87			95.8	
Particulates Removal, %		99.8			99.7			99.9	

1. Calculated based on air permit data, discussions with equipment suppliers, literature, and process model software.
2. Estimated from review of air permit data.

The high amount of ash (slag) in lignite makes it unsuitable for GE Energy's entrained flow gasifier, because heavy slagging of the radiant heat exchanger slows heat removal and exchange. Also, the need for high ash content slurry to be removed from the bottom of the gasifier which retains significant heat energy is another major source of heat loss. These two factors have significant impact on the thermal efficiency of the gasifier and overall IGCC plant. Although the GE Energy gasifier can handle high moisture coal, the efficiency loss from the ash content of lignite is significant enough to make it unattractive.

The Shell gasifier has a refractory-lined water wall for syngas heat removal which can handle high loading of ash and still be effective in heat transfer. There is no significant loss in efficiency in Shell gasifier.

Greater details of energy and material balances for the IGCC plants are included in Appendix C of this report.

Exhibits 3-4, 3-5, and 3-6 present summary performance data for the PC units and the three coals.

Exhibit 3-4 Subcritical Pulverized Coal Unit Performance Estimates

Subcritical PC	Bituminous	Subbituminous	Lignite
Net Thermal Efficiency, % HHV	35.9	34.8	33.1
Net Heat Rate, Btu/kWh (HHV)	9,500	9,800	10,300
Gross Power, MW	540	541	544
Internal Power, MW	40	41	44
Fuel required, lb/h	407,143	556,818	815,906
Net Power, MW	500	500	500

Exhibit 3-5 Supercritical Pulverized Coal Unit Performance Estimates

Supercritical PC	Bituminous	Subbituminous	Lignite
Net Thermal Efficiency, % HHV	38.3	37.9	35.9
Net Heat Rate, Btu/kWh (HHV)	8,900	9,000	9,500
Gross Power, MW	540	541	544
Internal Power, MW	40	41	44
Fuel required, lb/h	381,418	517,045	752,535
Net Power, MW	500	500	500

John W. Thompson
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EDUCATION

Master of Business Administration, Washington University, Olin School of Business Executive Program, St. Louis MO, 1999

Bachelor of Science in Chemical Engineering, University of Illinois, Champaign-Urbana, 1982. Graduated with Distinction

EMPLOYMENT

Clean Air Task Force, Boston, MA — *Oct 2001- Present*
Director, Coal Transition Project

- Review new conventional coal-fired power plants permits
- Evaluate economics and environmental characteristics of advanced coal technologies such as coal gasification
- Communicate potential health impacts of power plant pollution
- Review proposed state and federal power plant rules.

Illinois Environmental Council, Springfield, IL — *Nov.1997–Oct 2001*
Director Clean Air Programs

- Developed and lead a campaign to clean-up air emissions from coal-fired power plants on behalf of the Illinois Environmental Council.

Central States Education Center, Champaign, IL — *1984-1997*
Central States Resource Center
Executive Director (1984-Aug. 1996);

- Responsible for fundraising, program, staff development, board relations for the Centers. The Centers are two 35 year-old nonprofit organizations that assist citizens, governments, and businesses on solid, hazardous, and nuclear waste problems.

Illinois Environmental Council, Springfield, IL — *Spring 1984*
Legislative Liaison

Procter & Gamble Inc., Cincinnati, OH — *1982–1983*
Process Development Engineer

PRESENTATIONS

Gasification Performance, Presented at Platts 2nd Annual IGCC Symposium, Pittsburgh PA, May 10, 2006.

IGCC's Environmental Performance and Role in Mitigating CO2 Emissions, Infocast's IGCC Project Development and Finance Seminar, St. Louis, MO, November 14-16, 2005.

Public perception of Gasification, Presented at MIT Carbon Sequestration Forum VI, Cambridge MA, November 3, 2005.

Integrated Coal Gasification Combined Cycle (IGCC) Environmental Performance, Presented at Platts IGCC Symposium, Pittsburgh PA, June 2-3, 2005.

View from the States, Presented at Workshop on Gasification, sponsored by U.S. Department of Energy, the National Association of Regulatory Commissioners, the Gasification Technologies Council, and the Southern States Energy Board, United State Environmental Protection Agency, Knoxville TN, April 12-13, 2005.

Integrated Coal Gasification Combined Cycle (IGCC): Environmental Impacts and Policy Implications, Presented at STAPPA/ALAPCO Fall Membership Meeting, Couer d'Alene ID, October 27, 2004.

Coal Gasification-Air Pollution and Permitting Implications of IGCC, Presented at USEPA's Air Innovations Conference, Chicago, IL, August 2004.

The BACT Analysis: Does IGCC Meet the Test?, Presented at Workshop on Gasification Technologies, sponsored by U.S. Department of Energy, the National Association of Regulatory Commissioners, the Gasification Technologies Council, and the Southern States Energy Board, Indianapolis, IN, June 2004.

Coal Gasification: Hedging Against Climate Change in the Power Sector, Presented at the Western Governors' Association Energy Summit, Albuquerque New Mexico, April 14, 2004

IGCC as LAER/BACT for the Production of Electricity from Coal, presented at the 20th Annual International Pittsburgh Coal Conference, Pittsburgh PA, September 15-19, 2003.

OTHER ACTIVITIES

Co-Chair, Technologies Subcomitttee, Clean Coal Task Force, Westerrn Governors' Association, May 2005- Present

WALTER F. KOUCKY

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EDUCATION:

M.S., Environmental Science (Air Pollution Control), College of Civil and Environmental Engineering, University of Cincinnati (1984)
B.A., General Science, Hiram College (1978)

SUMMARY:

Mr. Koucky is a Senior Project Engineer; he has over 20 years of experience in environmental planning, modeling, permitting, monitoring, compliance and research. He has worked extensively with EPA headquarters, Regional offices, State and local programs. His current focus is on enforcement support. He also has experience in human exposure to toxic and criteria pollutants, control and control cost evaluation and regulatory development. During his career, he has developed expertise in a wide range of areas including risk assessment, risk management, regional and sector based initiatives, cost benefit analysis, teaching and training, permitting, enforcement, regulatory development, mobile sources, combustion and incineration, and control evaluation. Mr. Koucky is proficient in computer operations with experience in network development, database development, Geographic Information Systems, and data acquisition.

His support in developing regulations includes:

Part 70 and 71 Air Permit Rules under Title V-analysis of regulatory impacts,
Compliance Assurance Monitoring (CAM) Rule-analysis of regulatory impacts,
Cement Kiln Dust (CKD) Standard as a RCRA Special Waste,
Regulatory gap analyses for Surface Impoundments as RCRA Special Wastes,
Short-term Sulfur Dioxide Standard,
Regional Haze Rule-analysis of regulatory impacts, and
Combustion MACT-support in addressing public comments.

He has performed and reviewed indirect exposure risk assessments, trial burns and other technical information on numerous BIF and hazardous waste incinerators to support RCRA permitting in Regions VI and VII. He supported the US Army Chemical Demilitarization Command in permitting incinerators for the destruction of chemical weapons.

His recent projects include supporting EPA/OECA/ORE's national sector-based initiatives. He has performed inspections and permit (including PSD) reviews for Portland cement plants, glass plants, refineries, specialty chemicals, electric utilities, primary smelters, wood pulp and paper mills, and steel mills. He has worked extensively in the area of combustion and incineration and the cement industry and

supported Region 7 in the risk assessment and establishing of permit values for the first RCRA permit issued under the Combustion Policy. He supported development of the RCRA Special Waste Cement Kiln Dust Rule and regulatory gap analysis for Surface Impoundments under RCRA Special Waste Rules. He supported a steel drum manufacturer in the design and permitting of an incinerator and has supported clients in the wallcovering industry in a variety of control evaluation and permitting activities.

PROFESSIONAL EXPERIENCE:

April 2000 - Present: Eastern Research Group (ERG) and Independent Consultant:

Supported EPA ORE's national enforcement initiatives for Portland cement plants, glass plants, petroleum refineries and electric utilities. Supported TCEQ in evaluation of state-of-the-art NOx controls for Portland cement plants. Expert witness for Department of Justice in support of national electric utilities enforcement activities. Supported Environmental Defense in Alcoa Case and in BACT analysis for a proposed coal-fired power plant. Supporting ongoing investigations in steel mini-mills sectors involving PSD, NSPS and Title V violations. Supporting EPA's OAQPS in revising the OAQPS Control Cost Manual for air pollution control equipment. Supporting EPA's ORD in developing a protocol for Risk Management Evaluations (RME), the RME protocol will improve current engineering evaluations to include human health and environmental risk parameters. Supporting EPA's OSW in regulatory gap analyses to evaluate need for RCRA Special Waste rule to address risk from air pathway exposure to hazardous compounds from surface impoundments.

November 1990 - April 2000: Science Applications International Corporation (SAIC): Senior Project Engineer

Air Quality Planning/Enforcement-Acted as permitting expert for OECA national review of compliance information in Part 70 permit submittal and national review of synthetic minor permits under Part 70 (Title V). Developing enforcement targeting methods using Title V permit compliance information and Annual Compliance Certification information. Led PSD, air quality and RCRA incineration reviews for several sites in national multi-media enforcement initiative for the specialty chemical, electric utility, primary smelters, wood pulp and paper mills and steel industries and supported other air quality and RCRA incineration issues. Supported various enforcement actions involving short-term releases and toxic exposure for ammonia releases, open burning/open detonation and EPCRA releases.

Managed software development project for OMS non-road vehicle emissions model. Led technical analyses of control options for primary and secondary emissions of PM from mobile sources. Supported Y2K compliance audit for EPA's Office of Mobile Sources for Ann Arbor Testing Lab. Managed ambient monitoring network evaluation for CO and ozone for Des Moines, Iowa. Assisted in developing cost and fugitive dust emissions models for fugitive emissions of cement kiln dust.

Supported development of the revised ozone standards by evaluating impacts of standards revisions on existing air quality programs such as permitting, conformity and mobile sources. Managed Regulatory Impacts Analysis (RIA) and Information Collection Request (ICR) project for EPA's final Part 70 Operating Permits Rule changes published in August 1994 and the and the RIA and ICR for the proposed Part 71 rule, provided updates to NSR Reform and Part C and D RIA and ICR's based on state Part 70 workload submittals, managed project to develop RIA and ICR for the CAM Rule and managed technical analyses to support an RIA for the proposed short-term SO_2 standard. Participated in preparing air

quality analyses to support environmental impact statements for mining sites in Alaska and Idaho and for dredging in San Francisco Bay. Reviewed PSD permit for a mining site for the State of Arizona. Performed BACT analyses and drafted PSD and major NSR permits for chemical weapons incinerators of the Army's Chemical Demilitarization program. Managed Title V inventory support and permit development for NASA/Langley. Managed updates of BACT/LAER determinations to support permit decisions through the BLIS System. Managed project to update New Source Review Workshop Manual to reflect 1990 CAA changes. Instructor for University of Cincinnati/Environmental Training Institute teaching two USEPA air permits courses (APTI # 460 & # 461). Managed development of an expert system for New Source Review permit applicability determinations. Managed the development of a pen-based, air pollution inspection prototype system; this system utilizes dBASE files and pen-based menus to perform a standard compliance inspection. Managing RACT updates including inventories and control analyses for conformance with new CAA requirements for the Chicago area. Managed inventories and control options analyses for 15% Reductions for the Chicago area. Managed ozone RACT inventories, control and cost studies for Wisconsin, Michigan, and Indiana. Managed database development project for AIRS AMS 1990 baseline inventory for the State of Ohio. Developed methodologies for statewide mobile source emissions and ambient impacts analysis for California Energy Commission's environmental damage cost assessment model (AQVM).

Combustion, Risk Assessment and Hazardous Materials-Supported analysis of generation and disposal of combustion waste. Supported development of training materials for risk assessment with focus on cancer, non-cancer, exposure and uncertainty training courses. Supported analysis of controls, costs and benefits resulting form control of cement kiln dust. Managed Southeast Kansas Risk Communication Project to establish risk based monitoring values and sampling locations for impacts of multiple hazardous waste combustors in Southeast Kansas and key pollutants such as mercury and dioxins/furans. Managed project to improve design and obtain permits for drum reclamation incinerator. Managed direct and indirect risk assessments for Region VII RCRA/BIF permit evaluation of eight cement kilns burning hazardous waste and for various hazardous waste incinerators issues including evaluation of quarry and cement kiln dust as well as volatile hazardous waste emissions for a facility in Chanute, Kansas. Updated risk assessments performed by SAIC and other contractors in Region VII using revised equations and modeling parameters based on the Mercury Report to Congress. Reviewed trial burn, risk assessment and performed incinerator evaluation for CERCLA hazardous waste incinerator in Baton Rouge, Louisiana. Performed risk and/or hazard assessments for remedial activities at Superfund sites including creosote wastes at a wood treatment plant and an Shell Oil facility. Managed risk assessment for commercial hazardous waste incinerator in Kimball, Nebraska for EPA Region 7 and Nebraska DEQ. Performed pre-operational audit on chemical weapons incinerator in Toelle, Utah. Managed emissions inventory of combined HAPs and EPCRA Section 313 toxic air pollutants from federal facilities in Region VIII. Supported implementation of the free-market based Acid Rain Program and the Acidic Precipitation Report to Congress. Managing PSD air permits and conducted permit compliance audits for the US Army to construct incinerators for the destruction of the national stockpiles of chemical weapons.

Toxics Studies-Managed research project investigating information on biological and ecological impacts resulting from toxics deposition into the Great Waters. Supported analysis of nutrient deposition in Great Waters from Maine to Mexico. Supported the Lake Michigan LAMP providing analysis of non-point loadings for mercury. Supported the Great Waters Report to Congress. Developed GIS system, industrial profiles, and historic contamination information for PCB and DDT contamination of the Los Angeles Harbor for NOAA. Developed prototype GIS system for data management of air, water and solid and

hazardous waste facilities in the Los Angeles area. Developed methodologies and data for GIS targeting of monitor locations for PM_{10} and nationwide silica exposure. Provided air quality analysis including modeling, control equipment review, risk and exposure analysis for various RCRA corrective action, CERCLA RI/FS studies and EIS including chromium plating, CAFOs, landfills and harbor dredging projects. Developed training materials for performing air quality studies at RCRA corrective action sites. Assisted in evaluating control options for permit support document for RCRA Subpart X units. Managed project to evaluate control options for charcoal kilns. Provided modeling, inventory, emission estimation and exposure assessment for various projects including landfills and remediation sites.

October 1987 - October 1990: Engineering Science: Senior/Supervising Engineer

Responsible for air pollution control analysis support for government agencies and industrial facilities. In charge of supervising local area network and computer staff and operations. Developed emission inventories for Lake Michigan air toxics deposition and Transboundary Air Toxics exposure and deposition studies for USEPA, studies also included dispersion modeling and risk assessments. Developed specifications and manual for I/M programs in Virginia and Missouri. Managed and performed multimedia environmental audit for printing facility including SARA Title III compliance. Prepared air toxics inventory for New Jersey; activities include mobile, area and stationary source characterization. Design of software for emission inventory management. Preconstruction permit activities for traditional combustion sources and speciation and analysis for toxic substances. Performed quality assurance statistical analyses for California inspection maintenance programs. Developed a PC based system for New Jersey SO_2 study utilizing CAD system and custom software for mathematical cartographic coordinate conversion. Managed local area network and staff for office personal computer systems. Managed four post-87 ozone SIP inventories and a special study for USEPA concerning proposed acid rain policy implementation issues. Prepared control strategy analysis for fuel volatility measures for the South Coast FIP; designed an RFP tracking system for area and mobile sources for the South Coast FIP. Developed statistical analyses for California BAR I/M Referee quality assurance program. Wrote technical specification for Pennsylvania's centralized CEM data acquisition system. Managed study of free-market cap and trade programs for control of acid rain. Supported development of RCRA Part B permit for munitions incinerator at Pine Bluff Arsenal. Supported and led permitting, environmental audit and inventory support efforts for numerous industrial clients.

June 1984 - October 1987: Polk County Physical Planning, Des Moines, Iowa: Air Pollution Engineer

Review of all permits for pollution control equipment and combustion equipment for conformance with Federal, State and local codes. Conduct computer modeling to determine impacts of proposed projects. Established and enforced RACT measures for control of carbon monoxide and particulate matter. Performed as quality assurance officer for ambient pollutant monitoring program. Projects include installation of computerized data acquisition system and design and development of custom monitoring data calculation, reporting and statistical analysis software. Responsible for equipment selection, obtaining grants, software development, installation and operation of network. Conducted 100 to 200 inspections per year for compliance with Federal, State, and local codes. Certified in USEPA Method #9 as a smoke reader. Performed asbestos demolition inspections and microscopic identification of asbestos fibers. Involved in a variety of planning functions including preparation and review of environmental impact analysis, State implementation plan revisions, preparation of successful redesignation

demonstration for carbon monoxide and represented Polk County on Des Moines Area Transportation Planning Committee (local MPO).

April 1983 - June 1984: University of Cincinnati, Cincinnati, Ohio: Research Assistant

Emission Testing Group - Designed and constructed automotive test facility under Cincinnati Gas and Electric grant utilizing chassis dynamometer, CVS sampler, various bench instruments and custom computer software. Performed alternative fuel research on various gasohol fuels including effect on stoichiometric ratio and aldehyde emissions. Stationary Source Emission Compliance Testing Team, conducted compliance testing on various power plants and city owned facilities.
Energy Research Group - Refrigeration testing, energy transfer and heat loss research utilizing analog to digital converter and personal computer. Ceramic coating testing for insulation (infrared reflection) of mechanical and engine components.

January 1981 - April 1983: US EPA, Center Hill Facility, Cincinnati, Ohio: On-site Contractor

Conducted particulate measurement, chemical and instrumental analysis, joint N.O.I.S.H. and USEPA toxicology project. Generated standard toxic exposure environments for exposure of rats and monkeys to coal dust and diesel aerosols. Conducted research and maintained nephelometry, process instrumentation and data acquisition for joint N.I.O.S.H. and USEPA toxicology research project (coal dust and diesel exposure toxicology).

COMPUTER PROFICIENCY:

Word Processing software, spreadsheets, database programs (ACCESS, FOXPRO, dBASE), network experience with NOVELL, WINDOWS 95 and NT and CISCO routers.

REFERENCES:

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Steven Ellis	US DOJ/ENRD	202 514 3163
Richard Killian	EPA/Region 3	215 814 2159
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Attorneys for Intermountain Power Service Corporation

BEFORE THE UTAH AIR QUALITY BOARD

In the Matter of: Unit 3, Intermountain Power Service Corporation, Millard County, Utah DAQE-AN0327010-04	**INTERMOUNTAIN POWER SERVICE CORPORATION'S MEMORANDUM IN OPPOSITION TO THE UTAH CHAPTER OF THE SIERRA CLUB'S MOTION FOR SUMMARY JUDGMENT**

I. INTRODUCTION

Intermountain Power Service Corporation ("IPSC") opposes the Utah Chapter of the Sierra Club's Motion for Summary Judgment (the "Motion") related to the claims stated in Statements of Reason # 20, 21, and 22 of its proposed Second Amended Request for Agency Action. Sierra Club's Motion is based on disputed facts and misapplication of the law. It should be denied for the following reasons.

First, within the eighteen month window identified in the Approval Order and applicable state regulations, IPSC applied for, and the Utah Division of Air Quality ("UDAQ") considered and approved, an extension of time to begin construction of IPP Unit 3. Sierra Club's bald assertion that there was no extension simply ignores these facts and should be rejected.

Second, Sierra Club's claim that UDAQ improperly approved IPSC's decision to use an equivalent pulverized coal-fired boiler technology (super-critical instead of sub-critical) in constructing IPP Unit 3 likewise must fail because the two technologies are "equivalent" for UDAQ's purposes. Also, the law plainly allows UDAQ to make such a decision. Ironically, Sierra Club had long argued that IPSC must use super-critical technology before recently changing its position.

II. LEGAL STANDARDS

Under Utah law, the Board cannot grant Sierra Club's Motion unless (1) "there is no genuine issue as to any material fact" and (2) Sierra Club "is entitled to a judgment as a matter of law." *Norman v. Arnold*, 2002 UT 81 ¶ 15, 57 P.3d 997, 1001 (Utah 2002) (emphasis added); *see also* Utah R. Civ. P. 56(c) (same).[1] As this memorandum and the facts show: (i) the material facts regarding UDAQ's extension of the Approval Order are in dispute (*i.e.*, Sierra Club, with no factual basis, claims that the Approval Order deadline was not extended while IPSC provides factual support demonstrating that the deadline was extended); and (ii) material facts regarding UDAQ's decision that super-critical technology was equivalent to sub-critical technology are likewise disputed. Because material facts are in dispute, the Board cannot rule in favor of Sierra

[1] As IPSC explained in its Motion for Judgment on the Pleadings, Sierra Club bears the burden of proof with respect to each of its challenges to the Approval Order, including the issues discussed in this Memorandum. (*See* Memo. in Support of IPSC's Mot. for Partial J. on the Pleadings: Appeal Issues 1, 3, & 5 (02/26/07), at 5.) Also, though not material to this Memorandum, Sierra Club presents the wrong standard of review, and cites the incorrect supporting statute (relying on the standard of review specifically established for appellate courts), in its Motion. (*See* Mot. at 4-6.)

Club's Motion. Moreover, even if material facts were not in dispute, the law is against, not for, Sierra Club's positions. For that separate reason, the Sierra Club's Motion must fail as well.

III. BACKGROUND AND DISPUTED FACTS

Outlined below are the relevant facts. The statements in **bold** are Sierra Club's statements that show a dispute exists regarding that material fact. The existence of these disputed facts requires this Board to deny Sierra Club's Motion for Summary Judgment.

1. Since the 1980's, the IPP facility in Millard County has provided electrical power for use in Utah, running two pulverized coal-fired electrical generating units. (Mot. Ex. 1,[2] at IPSC 4333.)

2. In December 2002, IPSC filed a Notice of Intent (which was amended in May 2003) to construct and operate IPP Unit 3, a third pulverized coal-fired electrical generating unit at the IPP facility, which would also supply power for Utah. (Mot. Ex. 1, at IPSC 4333; Proposed Second Am. Request for Agency Action § III(A), at 2.)

3. IPSC initially intended that Unit 3 be a sub-critical pulverized coal-fired electrical generating unit. (Mot. Ex. 3.)

4. UDAQ received voluminous public comments on the IPP Unit 3 project, <u>including extensive arguments from Sierra Club</u> to the effect that IPP Unit 3 should be

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[2] Generally, to avoid duplication, referenced exhibits that were attached to Sierra Club's Motion are cited as "Mot. Ex. __," while exhibits attached to this Memorandum are cited as "Ex. __." Also, to differentiate between Sierra Club's exhibits, IPSC's exhibits are identified by letters rather than numbers.

constructed as a super-critical, rather than a sub-critical, pulverized coal-fired boiler unit. (Ex. A, at IPSC 4489; Ex. B; Mot. Ex. 3.)

5. After considering the comments and information from two separate, properly noticed public comment periods, UDAQ issued specific, detailed responses. (Ex. B.)

6. As to Sierra Club's contention that IPP Unit 3 should be constructed as a super-critical pulverized coal-fired boiler, UDAQ concluded that "supercritical boilers are no more effective than state-of-the-art sub-critical boilers in controlling emissions of regulated pollutants." (Mot. Ex. 4, at IPSC 4297.)

7. After addressing several issues with IPSC, UDAQ issued an Approval Order for the IPP Unit 3 project on October 15, 2004. (Mot. Ex. 1.)

8. The Approval Order ("AO") contains several key provisions that particularly undermine the arguments in Sierra Club's Motion:

- General Condition 4 provided: "Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved in accordance with R307-401-1."[3]

- General Condition 7 specified that "[t]he approved installations shall consist of" enumerated equipment or its "equivalent" and that "[e]quivalency shall be determined by the Executive Secretary."

- General Condition 8 provides: "If construction and/or installation has not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction

[3] R307-401-1 has since been changed and renumbered as R307-401-3.

and/or installation of the operation and may revoke the AO in accordance with R307-401-11."[4]

(Mot. Ex. 1.)

9. Fifteen months after the Approval Order was issued, on January 13, 2006, IPSC wrote to Richard Sprott, Executive Secretary of UDAQ, providing an update of Unit 3's construction status and requesting a twenty-four month extension of the time to commence construction. (Ex. C.)

Disputed Sierra Club Statement of Fact: "Eighteen months after the date of the AO – on or about April 15, 200[6] – IPSC did not submit the required notification of the status of construction." (Mot. at 7.) As Paragraph 9 above and Exhibit C demonstrate, Sierra Club's statement is completely false.

10. Two weeks later, on January 27, 2006, Sprott responded with a letter and memorandum to IPSC granting the requested extension. (Ex. D.)

Disputed Sierra Club Statement of Fact: "Eighteen months after the date of the AO – on or about April 15, 2006 – the Executive Secretary made no determination regarding a revocation of the AO, nor whether an extension of the AO was justified." (Mot. at 7.) As Paragraph 10 above and Exhibit D demonstrate, Sierra Club's statement is completely false.

11. On August 4, 2006, UAMPS (as one of the developers of IPP Unit 3 and on behalf of all of the developers) wrote to Sprott regarding its "intent to use a supercritical boiler design" for IPP Unit 3. (Ex. E, at IPSC 4479.)

12. Explaining the decision, UAMPS indicated "that a supercritical boiler design is more efficient and better for the environment, that it reflects the latest engineering and market

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[4] R307-401-11 has since been renumbered R307-401-18.

developments for PC [pulverized coal] facilities, and that it accommodates those who favored a supercritical boiler design in the comments regarding the AO." (*Id.* (emphasis added).)

13. Additionally, UAMPS explained that the super-critical and sub-critical designs are functionally equivalent:

- "A supercritical boiler is functionally equivalent to a subcritical boiler except that, in order to create greater efficiencies, a supercritical boiler generates steam at higher pressures and temperatures. This makes supercritical boiler-turbine technology more efficient in converting heat from the burning coal to driving the steam turbine generator. In all other respects, a supercritical boiler is equivalent to a subcritical design." (*Id.* at IPSC 4479-80.)

- "Using a supercritical boiler will not increase the heat input rate or the emission limits included in the AO." (*Id.* at IPSC 4480.)

- "Unit emissions, coal feed rate and heat input to the boiler will in all cases remain at or below the levels specified in the AO." (*Id.* at IPSC 4481.)

- "Installation of a supercritical boiler will result in a net decrease in emissions as measured in lbs/MWh. Also, as with the subcritical boiler design, the supercritical boiler will use a baghouse for particulate emissions control, a wet limestone scrubber for control of sulfur dioxide and acid gas emissions; and Low NOx Burners/Over-Fire-Air and Selective Catalytic Reduction for NOx emissions control. The design of the emissions control equipment will be the same as for the subcritical design." (*Id.*)

- "The BACT analysis completed for IPP3 showed that BACT-Level emission controls were the same for both designs." (*Id.*)

- "Whether the boiler is subcritical or supercritical design, the BACT process evaluates the same pollution control equipment." (*Id.*)

14. In response to UAMPS's letter and after consideration of its contents, UDAQ responded, "Utah Division of Air Quality agrees, that in accordance with Condition 7 of the Approval Order number DAQE-AN0327010-04*, a supercritical PC boiler is equivalent to the permitted unit." (Ex. F.)

Disputed Sierra Club Statement of Fact: "Importantly, there is no 'equivalency' determination in the record." (Mot. at 14.) As shown in Paragraph 14 above, UDAQ made a proper and legal equivalency determination.

15. The proposed super-critical unit is approximately three percent more efficient than the sub-critical boiler proposed by IPSC. (Ex. E, at 4480; Ex. G ¶ 8.)

Disputed Sierra Club Statements of Fact: (A) "the supercritical boiler will be approximately 7 to 9 percent more efficient than the subcritical boiler." (Mot. at 21.) Therefore, Sierra Club's efficiency number, as well at its increased megawatt estimate which relies upon the efficiency number, are disputed issues of fact.

IV. SIERRA CLUB'S CONTENTION THAT THE APPROVAL ORDER EXPIRED IS PREMATURE AND BASELESS.

On February 16, 2007, Sierra Club filed a Motion to Amend Request for Agency Action, seeking leave to file a Second Amended Request for Agency Action. In the proposed Second Amended Request, Sierra Club argues – for the first time – that the Approval Order is "invalid" because it "expired automatically" in April 2006. (Proposed Second Am. Request for Agency Action § III(B)(22), at 21.) Echoing this argument in its Motion, Sierra Club contends that, in light of the "invalid" Approval Order, it is entitled to judgment as a matter of law. Sierra Club's argument, however, is procedurally improper[5] and substantively incorrect.

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[5] As set out above, Sierra Club recently sought leave to file its Second Amended Request for Agency Action to include an additional new claim that the Approval Order is "invalid" because it has now expired. However, as of this filing, the Board has not ruled on Sierra Club's Motion to Amend Request for Agency Action. This is critical because the Second Amended Request is not effective unless and until (1) the Board grants that motion and (2) Sierra Club files the Second Amended Request. *See, e.g., Donner v. Sulcus Computer Corp.*, 103 F.R.D. 548, 549 (N.D. Ga. 1984) (concluding that "the amendment of a complaint is not effective until the amendment is filed with the court"). Neither of these prerequisite events has occurred and, accordingly, the substantive issue of whether the Approval Order "expired" is not

Even if Sierra Club's argument were properly before the Board – again, it is not for the reasons explained in footnote 3 – the facts demonstrate that the Approval Order did not expire by its own terms or by operation of law. Thus, Sierra Club's argument fails on the merits.[6]

Sierra Club concedes, as it must, that UDAQ has authority to extend the eighteen-month period. (Mot. at 11.) While Sierra Club says that "the Executive Secretary failed to conduct the mandatory 18-month review required under the regulations and permit conditions," (Mot. at 13), the fact is that UDAQ did just that.

UDAQ issued the Approval Order on October 15, 2004. Fifteen months later, on January 13, 2006, IPA wrote to Richard Sprott, Executive Secretary of UDAQ, and provided him an update of Unit 3's construction status as required by Condition No. 8 of the Approval Order. He also requested a twenty-four month extension of the period within which to commence construction, and explained the grounds for the proposed extension. (Ex. C.)

On January 27, 2006, two weeks after the IPA letter and after UDAQ duly considered and analyzed the issue, Sprott responded with a letter and memorandum confirming that (1) UDAQ had reviewed IPSC's Approval Order and the status of Unit 3's construction within eighteen months; (2) UDAQ granted IPSC a twenty-four month extension of time to commence construction; and (3) the Approval Order had not expired. (Ex. D.) Thus, because UDAQ

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now before the Board and cannot be considered as part of the current Motion. In light of this, Sierra Club's arguments regarding that claim should be stricken from the Motion.

[6] IPSC has already pointed this out in its March 5, 2007 Memorandum in Opposition to Sierra Club's Motion for Leave to Amend its Request for Agency Action, and the arguments in that Memorandum apply with equal force in response to Sierra Club's Motion.

properly extended the deadline for IPSC to commence construction of IPP Unit 3, the Approval Order did not "expire[] automatically," and Sierra Club's contrary argument fails on the merits.

V. UDAQ PROPERLY ALLOWED IPSC TO CONSTRUCT A SUPER-CRITICAL PULVERIZED COAL FIRED UNIT.

The other argument in Sierra Club's Motion relates to UDAQ's approval of IPSC's decision to use an equivalent pulverized coal-fired boiler technology (super-critical instead of sub-critical) in constructing IPP Unit 3. Sierra Club's contention again misses the mark.

Condition No. 7 of the Approval Order provided that the "approved installations" for IPP Unit 3 consisted of certain enumerated equipment or its "equivalent" and that "[e]quivalency shall be determined by the Executive Secretary." (Mot. Ex. 1.) In August 2006, UAMPS (on behalf of the IPP Unit 3 developers) wrote to UDAQ regarding IPP Unit 3's intent to use a super-critical pulverized coal-fired boiler, rather than a sub-critical pulverized coal-fired boiler, for Unit 3. (Ex. E.) UAMPS noted that this decision "accommodates those who favored a supercritical boiler design in their comments regarding the AO." (*Id.* at 4479.) UDAQ concurred, determining that, "in accordance with Condition 7 of the Approval Order number DAQE-AN0327010-04, a supercritical PC boiler is equivalent to the permitted unit." (Ex. F.)

Sierra Club – ironically, one of "those who favored a supercritical boiler design in their comments" – now objects to UDAQ's determination and insists that this decision is "unlawful." (Mot. at 14.) Sierra Club's arguments find neither factual nor legal support.

A. <u>There Is No Requirement For Public Comment Regarding The Change To Super-Critical Technology</u>.

Sierra Club says that the Approval Order requires public notice and comment for any modification to the Approval Order, including any "equivalency determination" by UDAQ under Condition No. 7. At the heart of Sierra Club's argument is Condition No. 4 of the Approval Order, which provides, "Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved in accordance with R307-401-1."

Sierra Club insists that "the only way to give effect" to Conditions No. 4 and No. 7 is to require "that even where there is a substitution of 'equivalent equipment,' if this 'modification to the equipment or processes . . . could affect' emissions, compliance with R307-401-1 is required prior to approval of the change." (Mot. at 19.) Accordingly, Sierra Club concludes, any equivalency determination under Condition No. 7 requires public notice and comment under Condition No. 4. This is simply not the law.

1. IPSC Did Not Modify Any Approved Equipment.

To begin, Sierra Club misconstrues the Approval Order in stating that the construction of a super-critical boiler "modifies" the approved equipment enumerated in Condition No. 7. In fact, Condition No. 7 is silent as to whether the approved boiler is sub-critical or super-critical, stating only that the approved boiler is (1) a "Unit 3 Dry-bottom Pulverized Coal Fired Boiler for base load operation with Overfire Air Ports System" or (2) the "equivalent" of such a boiler as "determined by the Executive Secretary." As UDAQ explained:

> The AO does not specify the temperatures and pressures of boiler that IPSC must build, only the emissions limitations that the facility must meet. Given that the AO is valid, IPSC is free to determine what type of boiler would best allow it to meet the terms of the AO.

(Ex. A.)[7] Thus, IPSC made no "[m]odifications to the equipment or processes approved by" the Approval Order to trigger Condition No. 4. Rather, the Executive Secretary determined that a super-critical pulverized coal fired boiler was the equivalent of a sub-critical pulverized coal fired boiler when both utilized the same state-of-the-art pollution control equipment. That is not a modification. Rather, it was an exercise of the discretion UDAQ expressly reserved under the Approval Order.[8]

2. Even If A Modification Occurred, It Was Proper.

Next, even if the equivalency determination under Condition No. 7 were considered a "[m]odification" of the approved equipment under Condition No. 4, there is still no public notice requirement because the potential "change" that Sierra Club recites in page after page of its Motion is "a net decrease in emissions," not an increase. (Mot. at 17 (quoting Ex. E, at IPSC 4481).) This distinction is important. Condition No. 4 provides that "[m]odifications to the

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[7] Notably, Sierra Club does not contend that a super-critical boiler would violate the Approval Order's emission limitations. To the contrary, Sierra Club complains that a super-critical boiler will reduce emissions.

[8] Sierra Club complains that UDAQ lacked the authority to reserve this discretion in the Approval Order, (Mot. at 19-20), but cites no authority for this proposition. In fact, in making the equivalency determination, UDAQ simply "responded to IPSC's request for an equivalency determination the same way it has responded to other similar requests. The Executive Secretary has consistently applied the rules this way, and sees no persuasive reason to depart from that practice." (Ex. A, at 4489.) Departing from UDAQ's established application of the rules at this point would be arbitrary and capricious. (*See id.*)

equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved in accordance with R307-401-1." While Sierra Club simply presumes that review and approval under this provision mandates public notice and comment for *any* modification resulting in potential changes in emissions, that is not the case.

At the time the Approval Order was issued, R307-401-1,[9] which Sierra Club chose not to quote, provided as follows:

> *Except for the exemptions listed in R307-413, any person intending* to construct a new installation which will or might reasonably expected to become a source or an indirect source of air pollution or *to make modifications* or relocate an existing installation *which will or might reasonably be expected to increase the amount or change the effect of, or the character of, air contaminants discharged*, so that such installation may be expected to become a source or indirect source of air pollution, or any person intending to install a control apparatus, or other equipment intended to control emission of air contaminants from a stationary source, *shall submit to the executive secretary a notice of intent and receive an approval order prior to initiation of construction, modification or relocation*. The notice of intent shall include the information described in R307-401-2 to determine whether the proposed construction, installation, modification, relocation or establishment will be in accord with applicable requirements of these rules. Within 30 days after receipt of a notice of intent, or any additional information necessary to the review, the executive secretary shall advise the applicant of any deficiency in the notice of intent or the information submitted. The executive secretary shall transmit to the Administrator, EPA, a copy of each notice of intent for each major source or major modification and provide notice to the Administrator, EPA, of every action related to the consideration of such permit.

R307-401-1(1) (2004) (emphasis added). Thus, as UDAQ succinctly – and correctly – explained in correspondence to Sierra Club several months ago, "*By its terms, R307-401 only applies to new sources or modifications that will "increase the amount of contaminants discharged* . . . ."

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[9] This provision is now largely found in R307-401-3.

(Ex. A, at IPSC 4488 (alteration in original & emphasis added).) Here – as shown in Section V(B) below – there will be no increase in the amount of, nor a change in the effect or character of, any air contaminants as a result of the change from a sub-critical to a super-critical pulverized coal-fired boiler. Accordingly, the provisions of former R307-401-1 as referenced in the Approval Order (as well as the current, renumbered rules regarding public review) do not apply.

Two additional points compel the same result. First, former R307-401-1 expressly recognized certain exemptions in then-existing R307-413. Two of those exemptions – R307-413-5 ("Replacement-in-Kind Equipment") and R307-413-6 ("Reduction in Air Contaminants") – provided that, where an operator with an existing approval order makes modifications to equipment that will either not impact emissions or will reduce emissions, "no public comment period . . . is required." R307-413-5(2)(b) (2004); R307-413-6(2) (2004).[10] Again, it is undisputed that emissions will not increase as a result of the change from a sub-critical pulverized coal-fired boiler to a super-critical pulverized coal-fired boiler. Thus, under former R307-413 (and the current equivalent of these provisions), this change was exempt from the public review provisions of former R307-401.

Also, as UDAQ has already indicated in correspondence to Sierra Club, public notice is not required in this instance because UDAQ has already issued a valid Approval Order:

> Likewise, *public comment for a new source review permit is only required prior to the issuance of an approval or disapproval order*. Utah Admin. Code R307-

[10] The current versions of these exemptions, found at R307-401-12 ("Reduction in Air Contaminants") and R307-401-11 ("Replacement-in-Kind Equipment"), likewise provide that "[p]ublic review . . . is not required . . . ."

> 401-7. However, as in this case, *when a source already has an approval order and requests a determination that their plans are consistent with the terms and conditions of its approval order, the Notice of Intent and its accompanying provisions do not apply. Instead, an equivalency determination is made using an approach similar to the in-kind replacement provision located at R307-401-11*. Should the Executive Secretary determine that the proposed action is indeed consistent with the terms and conditions of the approval order and that there is no violation of the rules, he informs the source of his concurrence with their determination. This type of action occurs rather routinely with the many sources the Executive Secretary permits throughout the state.

(Ex. A (emphasis added).)

In sum, there is no public notice or comment requirement with respect to IPSC's decision to use a super-critical pulverized coal-fired boiler rather than a sub-critical pulverized coal-fired boiler because it is undisputed that this will not lead to increased emissions.

B. UDAQ Made A Proper Equivalency Determination.

Sierra Club also says that UDAQ's equivalency determination was erroneous because of alleged differences between sub- and super-critical pulverized coal-fired boiler technology.[11]

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[11] Leading into this argument, Sierra Club asserts that "there is no 'equivalency' determination in the record" and that this proves that UDAQ "undertook no independent analysis of IPSC's statements regarding comparisons between sub-critical and super-critical technology at Unit 3." (Mot. at 14.) Sierra Club's literal argument ignores reality – in response to UAMPS's letter regarding the use of supercritical technology for Unit 3, UDAQ stated, "Utah Division of Air Quality agrees, that in accordance with Condition 7 of the Approval Order number DAQE-AN0327010-04*, a supercritical PC boiler is equivalent to the permitted unit." (Ex. F.) Given this straightforward language, it is evident that UDAQ made an "equivalency determination." Sierra Club's actual argument seems to be that, because UDAQ agreed with UAMPS without separately stating its rationale for doing so, it does not count as an "equivalency determination." Notably, Sierra Club cites no authority for this contention – and with good reason: "The rules do not require the Executive Secretary to undertake a separate analysis when there is no modification, as defined in the Air Quality Rules, Utah Admin. Code R307-401 et seq." (Ex. A.)

However, the evidence shows that sub-critical and super-critical pulverized coal-fired boiler technologies are extremely similar, and UDAQ's equivalency determination was proper.

Sierra Club's argument is a red herring, focusing on irrelevant power production issues. Additionally, the argument is based on incorrect information, including inapplicable portions of a document entitled "Final Report: Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies" (the "Report"). Sierra Club tries to bolster this Report though two affidavits from alleged "experts," Mr. Kouky and Mr. Thompson, who do no more than parrot the Report itself.

1. The relevant, undisputed facts show that, in this instance, the proposed sub-critical and super-critical pulverized coal-fired boiler units are equivalent.

To begin, the total estimated emissions from the proposed sub-critical and super-critical pulverized coal-fired units are identical:

	Permit Basis Sub-critical Design	Super-critical Boiler Design
Coal Feed Rate (tons/hr) Heat Input to Boiler (MMBtu/hr) Annual Capacity Factor (%/yr)	404 9050 100	404 9050 100
NOx NOx Boiler Emissions (lb/MMBtu) NOx Stock Emissions (lb/MMBtu)	0.35 0.070	0.35 0.070
SO_2 SO_2 Boiler Emissions (lb/MMBtu) SO_2 Stack Emissions (lb/MMBtu)	1.34 0.090	1.34 0.090
CO CO Emission Factor (lb/MMBtu)	0.154	0.154
Filterable PM Filterable PM Stack Emissions (lb/MMBtu)	0.013	0.013

Filterable PM_{10} Filterable PM_{10} Stack Emissions (lb/MMBtu)	0.012	0.012
VOC VOC Emissions (lb/MMBtu)	0.00268	0.00268
Sulfuric Acid Mist H_2So_4Stack Emissions (lb/MMBtu)	0.00439	0.00439
Ammonium Sulfate $(NH_4)_2SO_4$ Stack Emissions (lb/MMBtu)	0.00030	0.00030
Hydrogen Chloride HCI Stack Emissions (lb/MMBtu) HCI Stack Emissions (lb/hr)	0.00421 38.13000	0.00421 38.13000
Hydrogen Fluoride HF Stack Emissions (lb/MMBtu)	0.001	0.001
Stack Conditions Stack Exit Flow (acfm) Stack Exit Diameter (feet) Stack Exit Temperature (degF)	3,244,126 31.85 135	3,244,126 31.85 135

(Ex. E, at IPSC 4483.) As is obvious from a comparison of the sub- and super-critical columns, the relevant numbers for each technology match exactly. Sierra Club does not dispute this.

Rather, seemingly in an attempt to confuse the Board, Sierra Club focuses on the irrelevant difference between sub-critical and super-critical pulverized coal-fired boiler technologies as measured by emissions in pounds per **megawatt** hour.[12] But in doing so, Sierra Club does not analyze the data actually submitted to UDAQ. Instead, Sierra Club greatly exaggerates the differences between pulverized coal-fired technologies by relying on the Report (which relies, in turn, on outdated information) rather than actual information regarding the

[12] None of the information from the Report, cited in Sierra Club's motion, is relevant. UDAQ does not regulate power generation or its relative efficiency. Rather, UDAQ regulates emissions into the air.

proposed unit. This reliance is inappropriate for the fundamental reason that the Report does not analyze IPSC's proposed sub-critical or super-critical pulverized coal-fired boilers.

To explain, the Report summarily compares sub-critical and super-critical pulverized coal-fired boiler technology. In doing so, the Report makes the following assumptions about the pulverized coal (or "PC") power plants that it is comparing:

- PC plants with subcritical steam conditions of 2,400 psig and 1,000/1,000 F single reheat.
- PC plants with supercritical steam conditions of 3,500 psig and 1,050/1,050 F double reheat.

(Mot. Ex. 9, at 1-1.) With no basis for doing so, Sierra Club simply states that these figures are "almost perfectly analogous" and "almost identical" to the sub-critical and super-critical units proposed in this matter. (Mot. at 22 & n.41.) This is simply not the case.

In fact, the hypothetical plants modeled in the Report differ dramatically from the units that IPSC proposed. The sub-critical unit proposed by IPSC was more efficient, with steam conditions of approximately 2,535 psig and 1,050/1,050 F single reheat, and the super-critical unit had steam conditions of approximately 3,690 psig and 1,050/1,100 F reheat. (Ex. G; Ex. E, at IPSC 4480.)

The difference between the Report and IPSC's Approval Order is significant. Consider a point (which, again, is really irrelevant to the analysis required of UDAQ) repeated in Sierra Club's Motion – efficiency. Relying on the Report, Sierra Club asserts that super-critical units

are seven to nine percent more efficient[13] than sub-critical units. But this efficiency is exaggerated because the Report assumes a less efficient sub-critical unit than IPSC actually proposed. When one compares the more efficient sub-critical unit IPSC actually proposed to the proposed super-critical unit, it is apparent that the difference in efficiency is slashed by two-thirds, such that the estimated difference is about three percent. (*See* Ex. E, at 4480; Ex. G ¶ 8.) Sierra Club's reliance on the Report creates a question that, according to Sierra Club's faulty theory, is the definitive "disputed issue of material fact" precluding summary judgment.

Next, Sierra Club argues "that BACT must be revisited for the supercritical technology." (Mot. at 23.) Such an analysis would be the height of form over substance. The only record evidence is that "[t]he BACT analysis completed for IPP3 showed that BACT-Level emission controls were the same for both designs," sub-critical and super-critical. (Ex. E, at 4481.) Thus, "[w]hether the boiler is subcritical or supercritical design, the BACT process evaluates the same pollution control equipment." (*Id.*) That being the case, UDAQ is not required to repeat this analysis. Sierra Club has provided no evidence to the contrary.

2. The Report, Together With The Declarations Of Koucky And Thompson, Should Be Stricken.

Sierra Club's efficiency argument (again, irrelevant because regulated emissions remain the same) hinges almost entirely on the Report as bolstered by the declarations of Koucky and Thompson. However, under Utah law, neither the Report nor these declarations can be considered as part of Sierra Club's Motion.

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[13] Sierra Club admits that the record shows a roughly three percent efficiency increase. (Mot. at 9.) This alone creates a "disputed issue of material fact" precluding summary judgment.

To begin, the Report is irrelevant (it fails to address the proposed units at issue in this matter) and is hearsay (an out-of-court statement offered for its truth). *See* Utah R. Evid. 402 & 801. As such, it should not be considered by the Board at all. *E.g.*, *Johnson v. Hermes Assocs., Ltd.*, 2005 UT 82 ¶ 25, 128 P.3d 1151, 1159 (Utah 2005) (concluding that hearsay statements could not be properly considered as part of summary judgment proceedings).[14]

Sierra Club cannot salvage the Report by reiterating its content through the Koucky and Thompson declarations. Declarations "do[] not establish a material fact for the purpose of summary judgment because [they are] not in the form required by rule 56(c) of the Utah Rules of Civil Procedure," *i.e.*, they are "not in the form of an affidavit." *Pipkin v. Haugen*, 2003 UT App 216, 2003 Utah App. LEXIS 283 *2-3 (June 26, 2003).[15]

Second, both declarations opine that super-critical pulverized coal-fired boiler technology is more efficient and more environmentally friendly than sub-critical pulverized coal-fired boiler technology and opine regarding the relative efficiency gains allegedly related to the use of super-critical pulverized coal-fired boiler technology at IPP Unit 3. However, neither Koucky nor Thompson have shown that they are qualified experts who can legally offer such opinions.

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[14] Furthermore, the Report violates the Best Evidence Rule. Under the Utah Rules of Evidence, it is improper to submit a copy of a document, such as the Report, where, "in the circumstances, it would be unfair." Utah R. Evid. 1003. Such is the case where, as here, "only a part of the original is reproduced and the remainder . . . may disclose matters qualifying the part offered or otherwise useful to the opposing party." Fed. R. Evid. 1003 (Advisory Committee Notes) (interpreting the identical federal rule). Here, Sierra Club submits only a handful of pages from a Report that is over 150 pages long.

[15] Pursuant to Utah Rule of Appellate Procedure 30, a copy of the *Pipkin* opinion is attached as Ex. H.

"The critical factor in determining the competency of an expert is whether that expert has knowledge that can assist the trier of fact in resolving the issues before it." *Patey v. Lainhart*, 1999 UT 31 ¶ 15; 977 P.2d 1193, 1196 (quoting *Wessel v. Erickson Landscaping Co.*, 711 P.2d 250, 253 (Utah 1985)). Typically, such a showing is made by a review of the purported expert's training, experience, or education. *See id.* However, the Koucky and Thompson declarations do not meet this test.

As to Koucky's declaration and curriculum vitae, they are silent regarding any training, experience or education related to sub-critical and super-critical pulverized coal-fired boiler technology. Meanwhile, although Thompson's curriculum vitae makes broad statements that he has reviewed information regarding "power plants," the only specific training, experience, or education addressed in his declaration relates to the use of IGCC technology, a point well beyond the scope of Sierra Club's Motion. Indeed, there is nothing in Koucky or Thompson's declarations that make them any more qualified than any layperson to testify regarding sub-critical or super-critical pulverized coal-fired boiler technology. As such, they are unqualified to offer their opinions and, accordingly, the Board should not consider these declarations.

In sum, neither the Report nor the Koucky and Thompson declarations are properly before the Board and they should be stricken from Sierra Club's Motion.[16]

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[16] At minimum, IPSC should be given the opportunity to depose Kouky and Thompson to determine whether they are qualified to offer the opinions set out in their declarations. Furthermore, as part of the formal written discovery in this matter, IPSC has requested documents from Sierra Club that address the issues raised in these declarations. Before the Board rules on Sierra Club's Motion, fairness requires that IPSC be allowed to conduct additional discovery regarding the factual basis of that Motion. This is expressly allowed under

C. The Potential For Increased Power Production Does Not Violate The Approval Order.

Finally, Sierra Club argues that the construction of a super-critical unit would violate the Approval Order because it would result in IPSC "operating a 1007 to 1036 megawatt power generating unit" rather than a "950 megawatt power generating unit." (Mot. at 25.) Sierra Club points to Condition No. 6 of the Approval Order, which provides that IPSC "shall install and operate the nominal[17] 950 gross-MW power generating Unit 3 with dry-bottom pulverized coal fired boiler . . . as defined by this AO." (Mot. Ex. 1, at 3.) To begin, these figures are only estimates – the actual production is unknown until the unit is constructed, goes through a typical shake down period, and finally goes online. (Ex. G ¶ 9.) Moreover, Sierra Club simply extrapolates is figures from the Report, which is inapposite in that it does not address the proposed boilers in this matter. A comparison of those boilers shows a much more modest difference in efficiency, about three percent. (Ex. G ¶ 8.)

Furthermore, UDAQ is generally describing the proposed unit in Condition No. 6, not setting a limit on its power generation capacity. Indeed, not surprisingly, permitting under the Air Quality rules is designed to regulate air quality, not the amount of energy production.

Utah Rule of Civil Procedure 56(f). It is also particularly appropriate because the first round of dispositive motions was to focus solely on legal issues. Because Sierra Club exceeded the scope of that framework, IPSC is entitled to investigate its grounds for doing so.

[17] The use of the term "nominal" further indicates that the 950 MW number was not a limit imposed by UDAQ. Black's Law Dictionary defines "nominal" as "not real or actual, merely named, stated or given, without reference to actual conditions." The New Lexicon Webster's Encyclopedic Dictionary defines "nominal" as "existing only in name or form, not real or actual."

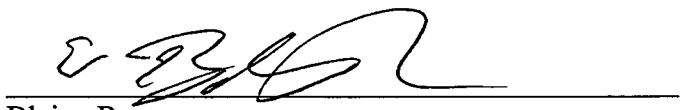
Moreover, Condition No. 6 indicates that the approved boiler is "defined by this AO." (*Id.*) As set out in section V(B), *supra*, UDAQ properly concluded that the super-critical pulverized coal-fired boiler fit the definition of the approved boiler – "Unit 3 Dry-bottom Pulverized Coal Fired Boiler for base load operation with Overfire Air Ports System" – in Condition No. 7 of the Approval Order. Thus, Sierra Club's argument on this point fails.

VI. Conclusion

As described throughout this Memorandum, multiple "genuine issues of material fact" preclude summary judgment on the claims in Statements of Reason # 20, 21, and 22 of Sierra Club's proposed Second Amended Request for Agency Action. And Sierra Club is not entitled to "judgment as a matter of law" because the applicable regulations and Approval Order conditions support IPSC's position, not Sierra Club's position. Accordingly, Sierra Club's Motion should be denied.

RESPECTFULLY SUBMITTED this 19th day of March , 2007.

HOLME ROBERTS & OWEN LLP



Blaine Rawson,
Holme Roberts & Owen LLP
Attorneys for Intermountain Power Service Corporation

CERTIFICATE OF SERVICE

I hereby certify that on 19th day of March 2007, undersigned served a copy of the foregoing on the following by:

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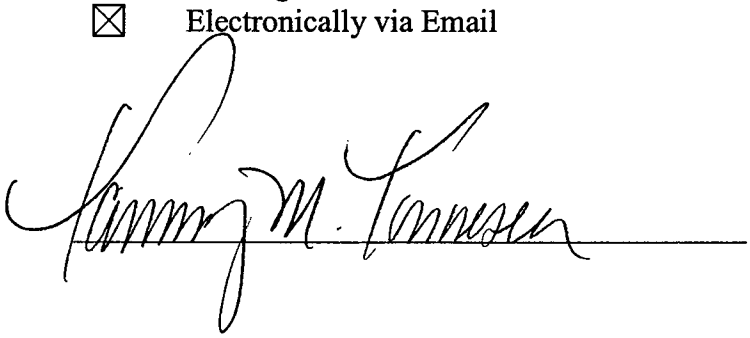

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Exhibits

Exhibit A – Stephens letter to Walker (11/15/06) (IPSC 4488-90)

Exhibit B – UDAQ responses to comments (10/14/04 & 10/15/04) (IPSC 4290-330)

Exhibit C – Searle letter to Sprott (1/13/06)

Exhibit D – Sprott letter to Searle (1/27/06)

Exhibit E – Hunter letter to Sprott (08/04/06) (IPSC 4479-83)

Exhibit F – Sprott letter to Hunter (08/17/06) (IPSC 4478)

Exhibit G – Affidavit of Thomas R. Ghesquiere

Exhibit H – *Pipkin v. Haugen*, 2003 UT App 216, 2003 Utah App. LEXIS 283 (June 26, 2003)

EXHIBIT A

STATE OF UTAH

OFFICE OF THE ATTORNEY GENERAL

MARK L. SHURTLEFF
ATTORNEY GENERAL

RAYMOND A. HINTZE
Chief Deputy

KIRK TORGENSEN
Chief Deputy

Protecting Utah • Protecting You

November 15, 2006

Joro Walker
Western Resource Advocates
425 East 100 South
Salt Lake City, UT 84111

Re: WRA Letter Requesting Public Comment on Division of Air Quality's Approval or Intermountain Power Service Corporation's Request to Change Unit 3 Boiler Technology

Dear Ms. Walker:

On behalf of Richard Sprott, Executive Secretary of the Utah Air Quality Board, this letter is in response to your letter of November 13, 2006 requesting a period of public comment regarding Intermountain Power Service Corporation's (IPSC) request for an equivalency determination on its proposed third unit and the Executive Secretary's concurrence that in accordance with Condition 7 of the Approval Order (AO), a supercritical PC boiler is equivalent to the permitted unit. The Executive Secretary values public input and recognizes the importance of an open and transparent administrative process for controlling harmful emissions. However, as explained below, the Executive Secretary does not believe that public comment is either appropriate or necessary under these circumstances.

Utah Administrative Code, Title R307, provides that a source wishing to construct or modify a source of air pollution must submit a Notice of Intent and follow all other regulatory requirements, including an opportunity for public comment. Utah Admin. Code R307-401 et seq; R307-405-7. By its terms, R307-401 only applies to new sources or modifications that will "increase the amount of contaminants discharged . . . ." Likewise, public comment for a new source review permit is only required prior to the issuance of an approval or disapproval order. Utah Admin. Code R307-401-7. However, as in this case, when a source already has an approval order and requests a determination that their plans are consistent with the terms and conditions of its approval order, the Notice of Intent and its accompanying provisions do not apply. Instead, an equivalency determination is made using an approach similar to the in-kind replacement provision located at R307-401-11. Should the Executive Secretary determine that the proposed action is indeed consistent with the terms and conditions of the approval order and that there is no violation of the rules, he informs the source of his concurrence with their determination. This type of action occurs rather routinely with the many sources the Executive

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Secretary permits throughout the state.

As noted, IPSC currently holds an Approval Order (AO) that allows construction of Unit 3. The AO does not specify the temperatures and pressures of boiler that IPSC must build, only the emissions limitations that the facility must meet. Given that the AO is valid, IPSC is free to determine what type of boiler would best allow it to meet the terms of the AO. The Executive Secretary has responded to IPSC's request for an equivalency determination the same way it has responded to other similar requests. The Executive Secretary has consistently applied the rules this way, and sees no persuasive reason to depart from that practice.

As a related but equally important matter, if the Executive Secretary were to release the equivalency determination for public comment, his actions would be a piecemeal and perhaps not even legal application of the administrative rules, as it could be considered an arbitrary action. As noted above, in other circumstances, the Executive Secretary has applied the rule the same way as he has with respect to IPSC, and does not desire to create new precedent, especially where the action you request is not required. While releasing the decision for public comment may be a gesture acknowledging the importance of public input, the permitting rules as currently constituted provide for public comment only during the Notice of Intent process. Yet IPSC has already completed that process and holds a valid AO. In fact, during the AO process for this particular source, the Executive Secretary went well beyond the regulatory requirements for taking public comment and giving the public opportunity to be involved in the process. Several meetings were held with interested parties to discuss issues of interest and concern beginning before the Executive Secretary even had a Notice of Intent from the source.

While there may be considerable disagreement between Sierra Club and the Executive Secretary as to whether the AO terms were proper in the first place, the AO is currently valid and the IPSC is not precluded from requesting an equivalency determination from the Executive Secretary. Aside from not being required by the rules, to require a source that has already received an AO and wishes to switch to a more efficient boiler to undergo the costly and time-consuming public comment process and risk an administrative appeal is to penalize the source for pursuing a more environmentally friendly alternative to the one originally permitted. For this reason the rules do not require such a process, as it would provide a robust disincentive for sources to seek better alternatives.

During the public comment period, Sierra Club submitted comments that argued in favor of a supercritical boiler. The Executive Secretary is at a loss to understand why Sierra Club now believes that the supercritical boiler is no longer preferable. In any event, the alternative types of emissions control technology referenced in your letter, while arguably appropriate subjects for discussion under the Notice of Intent process, are beyond the scope of IPSC's equivalency determination request. The only question raised is whether under the current permit, IPSC may substitute an equivalent boiler. The Executive Secretary answered that question in the affirmative. The rules do not require the Executive Secretary to undertake a separate analysis

when there is no modification, as defined in the Air Quality Rules, Utah Admin. Code R307-401 et seq.

Based on the foregoing, the Executive Secretary respectfully denies your request to provide public notice or a public comment period.

Please call Christian Stephens at (801)536-4137 with any questions.

Sincerely,

Christian C. Stephens
Paul M. McConkie
Assistant Attorneys General

cc: Richard W. Sprott, Executive Secretary
Cheryl Heying, Acting Executive Secretary
Christian Stephens, Assistant Attorney General
Regg Olsen, Permitting Branch Manager
Rusty Ruby, New Source Review Section Manager
Milka Radulovic, Permit Engineer
George Haley, Holme, Roberts, and Owen
Blaine Rawson, Holme, Roberts, and Owen

EXHIBIT B

Memorandum

To: Intermountain Power Service Corporation (IPSC) File (N327010)

From: Milka Radulovic, Environmental Engineer

Through: Rusty Ruby, NSR Section Manager, R 10/14/04

Regg Olsen, Permitting Branch Manager RDO 10/14/04

Date: October 14, 2004

Re: Response to Comments received on IPSC Intent to Approve number DAQE- IN327010-04

On April 1, 2004, a public comment period began to solicit comments on Intent to Approve (ITA) Intermountain Power Service Corporation's (IPSC) addition of New Unit 3 at their existing Intermountain Power Plant (IPP), located in Delta, Millard County, Utah. The IPSC proposed an electricity-generating unit with a pulverized coal fired boiler to provide 950 MW gross (900 MW net nominal) of electrical power. At the Millard County Economic Development Director's request a public hearing was held on April 29, 2004. The public hearing found overwhelming support for the new unit from the local population, medical and educational community.

In accordance with public request, the comment period was extended by twenty one (21) days.

On June 3, 2004, an additional 30-day comment period was started, to address shortcomings in the previous public notice of April 1, 2004.

Numerous comments were received, both during the comment period and at the public hearing. All comments received during the two public comment periods and the public hearing are listed here, with the original comments being included as an attachment. Following each comment is the Utah Division of Air Quality's (UDAQ) response, along with any action taken by the Division in regards to the final Approval Order (AO).

Quoted items are taken verbatim from the original comment submission. If the comment was unclear, UDAQ attempted to explain the comment as understood by the Division.

UDAQ responded to the following comments:

Comments made during the public comment periods (PCP) from April 1 to May 21 and from June 3 to July 3, 2004, and the public hearing (PH) of April 29, 2004.

Comments by Utah Chapter Sierra Club, Wasatch Clean Air Coalition, Grand Canyon Trust, Rocky Mountain Office of Environmental Defense, Western Resource Advocates, and Clean Air Task Force of May 20, 2004 (UWG). Our responses to UWG comments of May 20, 2004 also provide, by reference, responses to UWG comments of April 14, 2003. On April 14, 2003, UWG submitted comments regarding the December 23, 2002 Notice of Intent (NOI) for the IPP Unit 3. However, the IPP Unit 3 project was not available for public comment until April 1, 2004. Nevertheless, UDAQ has considered these comments as well.

Comments by UWG of June 30, 2004 and July 16, 2004.

Comments by National Park Service (NPS) of May 27, 2004. Our responses to NPS comments of May 27, 2004 also provide, by reference, responses to NPS comments of March 25, 2004.

Comments by Environmental Protection Agency (EPA) of May 24, 2004.

Comments by Intermountain Power Service Corporation (IPSC) and Intermountain Power Agency (IPA) of May 21, 2004.

Modeling questions made in the above referenced documents were reviewed and responded to by the UDAQ Technical Analysis Section. These responses are provided in the file.

Comment #1

Sixty-one individuals and seven groups submitted comments expressing general approval of the proposed project. (PCP/PH)

Response

The comments were noted. As no legal or technical issue was raised with respect to the ITA, no changes were made to the Approval Order (AO).

Comment #2

One individual submitted comment of general opposition to the new unit. (PCP/PH)

Response

The comment was noted. As no legal or technical issue was raised with respect to the ITA, no changes were made to the AO.

Comment #3

A representative of UWG made a number of specific comments on the ITA during the public hearing. (PCP/PH)

Response

Response to these comments is incorporated in the response to the identical written comments submitted by the same group starting with Comment 6.

Comment #4

One individual questioned why the amount of mercury emitted in California was much smaller that the proposed emissions of mercury from the Unit 3. The commenter wanted to know if the mercury emission from the Unit 3 would be controlled to the level comparable with California. (PCP/PH)

Response

Emissions of mercury will be reduced to the maximum achievable control technology level in accordance with the EPA proposed rule, 40 CFR Parts 60 and 63, National Emission Standards for Hazardous Pollutants; and, in alternative Proposed Standards of Performance for New and Existing Stationary sources: Electric Utility Steam Generating Units (69 F R 4652 - 4752 January 30, 2004). No data was submitted by the commenter to support a suggestion that a higher level of mercury emission reduction is achievable for Unit #3. No changes were made to the AO.

Comment #5

One individual expressed concern about the "yellow/brown cast to the wide sky" and "plume of smoke that fills up the valley". The commenter is "urging" UDAQ "to take into account the amount that is foisted into our lives". (PCP/PH)

Response

The comment was noted. As no legal or technical issue was raised with respect to the ITA, no changes were made to the AO.

Comment #6

> "IPSC failed to submit a complete permit application and thus consideration of the permit application is premature." (UWG, p.2)

Response

All information submitted by IPSC was considered in the technical review by UDAQ. The application was deemed to be administratively complete before the draft Approval Order was available for public comment. The public had full opportunity to comment on all aspects of the Approval Order. No changes were made to the AO.

Comment #7

> "According to 40 CFR 51.307, UDAQ should have provided the FLM with all information relevant to the permit application at least 60 days prior to the April 29 public hearing..." (NPS, p.13)

Response

Consistent with the requirements of R307-406-3(1), UDAQ provided the Federal Land Manager (FLM) with all information relevant to the NOI, including the ITA (draft AO) and staff analysis, 60 days prior to the April 29 public hearing. Further, UDAQ provided the FLM the opportunity to submit a visibility analysis within 30 days of the UDAQ's preliminary determination and before announcing the public comment period. We list some of the key communications to the FLM:

- On December 06, 2002, UDAQ staff had a pre-application meeting regarding IPP Unit 3 with representatives of IPSC, NPS, EPA Region 8, and UAMPS.
- On December 23, 2002, UDAQ submitted the NOI for IPP Unit 3, dated December 14, 2002, to NPS.
- On May 30, 2003, UDAQ submitted Addenda to the NOI, dated May 14, 2003 and May 27, 2003, to NPS.
- On June 20, 2003, UDAQ sent Replacement of the NOI Sections 7 & 8 and Appendix E to NPS.
- On March 1, 2004, before the NPS, UDAQ and IPP meeting of March 4, 2004, UDAQ e-mailed a draft Modified Source Plan Review to NPS.
- On April 1, 2004, UDAQ published the first Public Notice and on June 3, 2004 the second one.
- On April 29, 2004, UDAQ held a Public Hearing.

The submitted documents had all information relevant to the IPP Unit 3 permit application, including analyses of the anticipated impacts on visibility in Federal Class I areas. In addition,

UDAQ communicated to NPS additional relevant information in numerous phone conversations and e-mails e.g. on October 31, 2003, November 3, 2003, November 4, 2003 etc.

In summary, UDAQ provided the FLM with all information relevant to the permit application in a timely manner. No changes were made to the AO.

Comment #8

> "Public notice lacks certain information required by Utah Air Quality Rules." (EPA, p.7)

Response

UDAQ responded to this comment by adding to the public notice of April 1, 2004 the relevant information; the public notice of June 3, 2004 incorporates all the required information. A second comment period was conducted to ensure the public was aware of and could consider all information required by Utah rules. No changes were made to the AO.

Comment #9

> "BACT definition and process" (NPS, p.5)

Response

The commenter cites two statements of EPA policy from the 1990 draft New Source Review Workshop Manual:

- *"Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternative."*
- "A permitting authority does have *"the discretion to engage in a broader analysis if they so desire."*"

UDAQ recognizes these statements of EPA policy. As no legal or technical issue was raised with respect to the ITA, no changes were made to the AO.

Comment #10

> "Clean Coal Technologies" (NPS, p.6)

Response

UDAQ has reviewed this issue in light of the comment. Based on all available information, UDAQ has concluded that Integrated Gasification Combined Cycle (IGCC) and Circulating Fluidized Bed (CFB) have been considered appropriately. There are three relevant facts:

- IGCC and CFB would require redefining the design of the source.
- Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives.
- Even if a top-down BACT analysis were required, both IGCC and CFB would be eliminated.

Comment #11

"Circulating Fluidized Bed" (NPS, p.7)

Response

Please see the response to Comment #10 above. Based on all available information, UDAQ has concluded that CFB boilers have been considered appropriately. Additionally, a top-down analysis including CFB as an available option, though not required, was provided by IPP. This analysis shows that CFB would not be appropriate for the IPP project. Also, CFB boilers are no more effective than new PC boilers in controlling emissions of most regulated pollutants. At this point in time, the new emission limits for the IPP Unit 3 are the most stringent emission limits, that we are aware of, imposed by any permit, granted or pending, on pulverized coal-fired boilers in the U.S.A.; these emission limits compare favorably to the emission limits for CFB boilers.

Comment #12

"Federal and state clean air laws require IPSC to consider the application of production processes and available methods, systems and techniques to lower airborne contaminants." (UWG, p.3)

Response

Please see the responses to Comments #9 and #10.

UDAQ recognizes and strictly applies both federal and state clean air laws regarding the application of production processes and available methods, systems, and techniques for control of pollutants. For example, we have reviewed and approved the proposed application of production processes such as fuel combustion techniques: ultra low NO_x burners and over-fire air. We have also reviewed and approved the proposed application of methods, systems, and techniques such as add-on controls: wet limestone flue gas desulphurization, selective catalytic reduction, and fabric filter baghouses. The text of the comment, however, identifies one particular production process that the commenter feels should be included in the BACT analysis: IGCC. UDAQ has reviewed this issue and has concluded that neither federal nor state clean air laws require this. Nevertheless, we did review an analysis of IGCC as a part of our permitting process.

That IGCC is not structurally similar in design and capacity to other coal-fired facility is generally understood. IGCC is not based on coal combustion but on coal gasification; the two processes are fundamentally different. Furthermore, IGCC and pulverized coal (PC) units cannot use the same control technology.

The commenter quotes from CAA 165(a)(4) and 40 CFR 51.166(j) to demonstrate that any major emitting facility is subject to BACT. UDAQ agrees.

The commenter quotes from Utah rules a paragraph defining BACT and concludes, "Thus, the BACT requirement must be implemented and construed under Utah law at least as strictly as EPA and the federal courts have construed it." UDAQ agrees.

The commenter then states, "This definition includes coal gasification." UDAQ does not agree. Further, the practice of environmental protection authorities over the years does not support it either.

The commenter also quotes the Ninth Circuit Court in *Citizens for Clean Air v EPA*, "initially the burden rests with the PSD applicant to identify the best available control." Similarly, they quote from an EPA guidance document. UDAQ agrees that the applicant must identify the best available "control" and consider all possible control alternatives for the proposed source. In this case the proposed source is a PC boiler.

The commenter then quotes from the 1990 draft New Source Review Workshop Manual (p. B.5) to show that "the applicant *must* consider all "available" control options". We repeat the quote (emphasis added):

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

The draft Workshop Manual states clearly "*all 'available' control options*" "*for the emission unit in question*". It also says "*with a practical potential for application to the emission unit ...under evaluation*". As shown by these passages from the draft Workshop Manual, EPA's interpretation of the statutory BACT requirement is that the applicant must consider all available control options but only for the emission unit in question. UDAQ adopts a similar interpretation. In this case, the unit in question is a pulverized coal-fired boiler. Also, "*production processes or available methods, systems, and techniques*" are "*for control of the affected pollutant*". And finally, it says "*as discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.*" This later discussion clarifies the circumstances: "*Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives.*" IGCC application would require redefining the design of the source.

The commenter next quotes from several sources to suggest that the meaning of the term "available" includes IGCC.

First, they refer to the U.S. EPA Environmental Appeals Board (EAB) decision In re: Maui Electric Company, which in turn quotes from the draft Workshop Manual at p. B.17. We agree that IGCC could be obtained by the applicant "through commercial channels." However, it is not an available control technology and it is not appropriate for consideration in the BACT analysis for the source under consideration.

Second, they refer to the EAB decision In re: Knauf Fiber Glass, which in turn quotes from the Manual at p. B.5; the commenter provides a quote that we repeat with our own emphasis added:

> *" "available" is used in the broadest sense under the first step and refers to* ***control options*** *with a "****practical potential*** *for application to the* ***emission unit****"*

> ***under evaluation****....The goal of this step is to develop a comprehensive list of control options."*

As above, we find the plain language of the Manual clear. U.S. EPA's interpretation, as set forth in the draft Workshop Manual, is that the scope of the BACT analysis is limited to control technologies that can be applied to the emission unit proposed by the applicant. IGCC is not a control option with a practical potential for application to the emission unit under evaluation i.e. a pulverized coal-fired boiler.

Third, the commenter quotes from the EAB decisions In re: Spokane Regional Waste-to-Energy Applicant and two other appeals of BACT determinations for municipal waste combustors; the commenter presents a quote that we repeat (emphasis added):

> "Under the top-down methodology, applicants must apply the best available **control** technology unless they can demonstrate that the technology is technically or economically infeasible. The top-down approach places the burden of proof on the applicant to justify why the **proposed source** is unable to apply the best technology available."

In response, UDAQ first notes that quote does not accurately reflect the BACT requirement under the PSD statute and regulation. Second, UDAQ does not find that IGCC is a "control technology," such as baghouses, electro-static precipitators (ESPs), cyclones, etc.; Unlike these control technologies, application of IGCC would require replacement of the proposed source in its entirety.

As required by state and federal law, UDAQ has thoroughly evaluated all available control measures potentially applicable to the proposed unit i.e. the pulverized coal-fired boiler.

We find that, contrary to the commenter's contention that the definitions of BACT under Utah and federal law, and the core requirements of the BACT analysis under federal case law, EPA adjudicatory decisions, and the New Source Review Manual, do not demonstrate or even imply that an available technique such as IGCC must be identified and evaluated as a control option in the first step of the BACT analysis.

UDAQ finds that the analysis of IGCC, as was done, is sufficient and that broader analysis is not required.

Comment #13

> "Recent state actions requiring consideration of IGCC establish irrefutable precedence for the consideration of IGCC." (UWG, p.6)

Response

UDAQ has reviewed this comment and the presented information. Recently, the permitting authorities of two states, Illinois and New Mexico, have decided to exercise their discretion and request the applicants include IGCC in their BACT analyses. The results of the requested BACT analyses are not available yet. Regardless of the outcome of those analyses, the interpretations made by other permitting authorities implementing the BACT requirement under other states' regulations have no effect in Utah.

In other recent applications for coal-fired units, the permitting authorities have not requested the applicants include in their BACT analysis production processes different than the proposed one. These states are Kansas, Missouri, Montana, Wyoming, Kentucky, Wisconsin, Arkansas and West Virginia. Also, as mentioned previously, although not required, the applicant provided and we reviewed a detailed analysis of IGCC.

Comment #14

> "IPP failed to correctly address IGCC in the BACT analysis and the permit must be denied. A properly conducted BACT analysis shows IGCC is BACT for the IPP project." (UWG, p.8)

Response

UDAQ has reviewed this issue in light of the comment. As discussed in the response to Comment #12 above, UDAQ has concluded that IGCC has been properly addressed. Additionally, a revised top-down analysis, though not required, has been provided by IPP. This analysis shows that IGCC would not be appropriate for the IPP project.

Comment #15

> "UDAQ and IPSC should have considered a supercritical pulverized coal boiler for the new unit." (UWG, p.22)

Response

UDAQ has reviewed this issue in light of the comment. Based on all available information and the discussion above, UDAQ has concluded that supercritical pulverized coal boilers have been considered appropriately. Additionally, a top-down analysis including supercritical boiler technology, though not required, was provided. That analysis shows that supercritical boilers would not be appropriate for the IPP project. Also, supercritical boilers are no more effective than sate-of-the-art subcritical boilers in controlling emissions of regulated pollutants. At this point in time, the new emission limits for the IPP Unit 3 are the most stringent emission limits, that we are aware of, imposed by any permit, granted or pending, for a pulverized coal-fired boiler in the U.S.A.., whether subcritical or supercritical. For example, see the proposed emission limits for supercritical boilers in three recently issued or pending permits: MidAmerican Energy, Longview Power, and Elm Road.

The paper by Bartolomei, referenced in the comment, provides information on expected rates and not on emission limits. In addition, the statements by Bartolomei are opinions and not commercial offers backed-up by guaranties. Thus, they are not properly part of a BACT analysis except for general information.

The commenter points out the proposed emission limits for the planned Steag facility to reinforce their comment. We have reviewed the PSD permit **application** for Steag Power's Desert Rock Energy facility and there are some issues that we point out regarding this application. First, this is only an application; the permitting process is in a very early stage. Obviously, the existence of a permit application, with no issued permit and no facility, does not provide any information that is informative as to technical feasibility and achievability of a particular emission limit. Second, the application seems to be substantially inconsistent regarding the sulfur dioxide emission limits. For example, we find the following statement on page 4-11: "Steag is proposing to limit SO_2

emissions to 0.06 lb/MMBtu as a 30 day average and 0.09 lb/MMBtu as 24-hour average..." However, on page 6-3, we find that 0.06 lb/MMBtu is listed as an annual average and 0.09 lb/MMBtu as a 3-hour average. Then, in Table 3-2 of Attachment 3, we find that 0.06 lb/MMBtu is listed as a 24-hour average. Third, the application seems to propose an emission limit for a 30-day average and not for a 30-day rolling average; that is a substantially less stringent limit. Fourth, the predicted air quality impact from the proposed project is very high for Navajo Nation Territory. The sulfur dioxide concentration, based on 0.09 lb/MMBtu emission, is 76% of the PSD Class II increment for a 3-hour averaging period, as shown in Table 6-6a. This indicates a need for stringent limits beyond BACT. Finally, the Desert Rock Energy facility is a proposed mine-mouth plant implying less variable coal quality and, in particular, less variable sulfur content than for the IPP Unit 3. For all these reasons, we believe that the proposed sulfur dioxide emission limits for the Desert Rock Energy facility have only a limited relevance at present.

Finally, the commenter states, "Xcel Energy is also **considering** the construction of a supercritical boiler for a new proposed unit at its Comanche plant in Pueblo, Colorado" (emphasis added). This is not sufficient to include in a BACT analysis.

Comment #16

> "The ITA fails to address carbon dioxide and other greenhouse gas emissions." (UWG May 20, 2004, p.22 and UWG June 30, 2004, p.2)

Response

UDAQ reviewed this issue in light of the comments of May 20, 2004, the supplemental comments of June 30, 2004 as well as the second supplemental comments of July 16, 2004. The second supplemental letter provided a copy of Petitioners' Appellate Brief in Commonwealth of Massachusetts v. EPA, Civil Action No. 03-1361 (D.C. Cir.). It was received after the closing of the second comment period and therefore did not need to be considered by UDAQ. Nevertheless, based on all available information, we found it proper that the ITA did not address greenhouse emissions. UDAQ believes that regulating greenhouse gas emissions is not required. The reasons are as follows:

- Historically, permitting authorities have not considered greenhouse gas emissions;
- The Clean Air Act and by extension, EPA do not regulate greenhouse gas emissions;
- While there is a petition in the court requesting that EPA reconsider the issue, the court has not ruled yet; oral arguments are scheduled for April 8, 2005;
- It is not prudent for UDAQ to take any action until after the court ruling; indeed it would be ill advised to take any action prematurely.

UDAQ believes that the CAA, NSR provisions and Utah's administrative rules do not require regulating greenhouse gas emissions.

Comment #17

> "UDAQ and IPSC should have evaluated the use of K-fuels." (UWG, p.23)

Response

UDAQ has reevaluated the use of K-fuels in light of the comment. Based on all available information, UDAQ finds the following:

- The K-fuel is not even available for sale yet; the first plant is not scheduled to start operations until 2005;
- There is no commercial experience with this technology;
- The technology is complex and will pose significant technical and economic risks;
- The technology may eventually prove attractive for subbituminous coals; its advantages are more questionable for bituminous coal.

Therefore, we conclude that K-fuels are neither available nor technically and economically feasible for the IPP Unit 3.

Comment #18

> "UDAQ improperly eliminated use of lower sulfur coal based on unreasonable costs." (UWG, p.24)

Response

UDAQ has reviewed this issue in light of the comment. Based on all available information, we find that lower sulfur coal was justifiable eliminated based on economic impacts. The 1990 draft New Source Review Workshop Manual, referenced by the commenter, is a draft statement of EPA policy; it is not a part of EPA's or Utah's PSD regulations. UDAQ does not necessarily adhere to the prescriptive procedural "requirements" in this manual. Regardless, in this instance, the procedure used is consistent with that suggested by the Workshop Manual. Utah coal is the "base case" (or "baseline" as described in the 1990 draft Workshop Manual), and PRB coal is the only more stringent control technique being evaluated. Thus the difference in costs and SO_2 emissions between these two control techniques represents both the average cost effectiveness and the incremental cost effectiveness.

In addition, the projected sulfur content was used for calculations as seen in Table 1 on page 109 of the Modified Source Plan Review.

Comment #19

> "The SO_2 emission limits are not reflective of the maximum reductions achievable with the SO_2 wet scrubber." (UWG, p.25)

Response

UDAQ has reconsidered the sulfur dioxide BACT analysis and associated emission limits in light of the additional information provided by the commenters. We have also requested and obtained additional information from IPP. Based on all additional information, UDAQ believes that more stringent emission limits for sulfur dioxide are achievable with the proposed WFGD system on the IPP Unit 3. The following limits will be in the AO:

0.10 lb/MMBtu on a 24-hour block average and
0.09 lb/MMBtu on a 30-day rolling average.

These are the most stringent sulfur dioxide emission limits, that we are aware of at this point in time, imposed by any permit, granted or pending, for a pulverized coal-fired boilers in the U.S.A.

The commenter presents information on control efficiency achieved with the proposed SO2 control equipment. UDAQ properly applied BACT as defined at R307-101-2. Under the regulation, BACT is "an emission limitation" that is "based on" the maximum degree of

reduction in emissions. An operational requirement, such as a minimum control efficiency, may be prescribed instead, if the reviewing authority determines that the imposition of a numerical emission limitation is infeasible. This is not the case for SO_2. In these instances, UDAQ imposes numerical emission limitations.

In addition, the commenter presents information on emission rates achieved at various existing pulverized coal-fired boilers. We have given full consideration to these data and, as a result, we have concluded that the appropriate BACT emission limits are those listed above. We recognize that these emission limits represent a nominal control efficiency that is numerically lower than that indicated by the actual emissions data from some existing, well-controlled boilers. This is by design and is necessary, because the BACT emission limit must be set at a level at which the source is able to achieve continuous compliance. The limit cannot be set at a level that represents the expected average actual emissions because the wource would then be out of compliance during some operating periods (i.e., whenever the emissions are above the long-term average). It is generally understood that an imposed limit must be greater than an achieved rate to account for variability. There are numerous sources of this variability. Some of them are: uncertainty in measurements, variability in coal, variability in performance of control equipment, variability due to aging of the plant, etc. None of the data presented by the commenter provide a demonstration that the IPP Unit #3, if properly designed and operated, can achieve continuous compliance with emission limits that are more stringent than those set forth in the AO.

Also, the commenter claims that "EPA's recently proposed BART guidelines propose 90-95% SO_2 removal at existing facilities as a retrofit requirement underscores that new facilities should be able to meet or exceed the 95% SO_2 removal requirement". A review of the proposed BART rule (Federal Register, Vol. 69, No. 87, May 5, 2004, pages 25199 and 25200) reveals the following:

- EPA proposes SO_2 emission limits not control efficiency for Western coals;
- EPA provides clear justification for this proposal;
- EPA considers a SO_2 emission rate of 0.10 lb/MMBtu for 0.7% sulfur Western coal demonstrated; this is the rate set by UDAQ for the IPP Unit 3.

Comment #20

"SO_2 Controls" (NPS, p.2)

Response

Please see the response to Comment #19 above.

The SO_2 emission limit of 0.15 lb/MMBtu for 3-hour averaging period will be provided for NAAQS protection. It is enforceable and consistent with the proposed BACT emission limits but it is not part of BACT analysis.

Based on data provided in NPS Table 1.a. for 3-hour averages:

- The new emission limit for IPP Unit 3 is the same as the proposed emission limit for Hardin, Roundup, WYGEN2, and Longview boilers. The projected sulfur content of the design coals for these boilers, expressed as weight percent, are 0.75, 0.64, 0.94, 1.20 and 2.5, respectively; they vary substantially, yet the emission limits are the same. We believe that this is appropriate because of the unpredictable nature of 3-hour variability; the coal sulfur content is only one of the factors.

- The emission limit of 0.15 lb/MMBtu is very close to the emission rates achieved at Colstrip #3 & #4; the difference represents a reasonable safety factor provided to allow for continuous compliance.
- We have given proper consideration to the PSD permit application for Steag Power's Desert Rock Energy facility. However, Steag Power has only limited relevance; please see the response to Comment #15.

Comment #21

> "BACT emission limit for sulfur dioxide should be more stringent." (EPA, p.1)

Response

Please see the response to Comments #15, #19 and #20. These responses are supplemented with responses to specific paragraphs in the comment.

UDAQ has reconsidered the projected coal sulfur content. We have requested and obtained relevant information from IPP; the following quotes are from the IPP (Technical Memorandum, December 18, 2003):

> "It can be seen from Figures 2 and 3 that the average sulfur content of Utah coals shipped to both Intermountain and Hunter increased between the years 2000 and 2002. It can also be seen that the standard deviation of the sulfur content of the fuel shipments has increased during the same time period. An increase in the standard deviation of the fuel sulfur content points toward increased variability in the fuel sulfur content. As discussed in IPP's coal study (referenced above) this trend is expected to continue as higher quality coal mine reserves are depleted.
>
> Because IPP must permit Unit 3 for the life of the unit, the permit application must include a reasonable estimate of the anticipated future coal characteristics. Based on a review of data from Utah mines, IPP concluded that a sulfur content of 0.75% represents a reasonably conservative estimate of future Utah coal reserves. Therefore, IPP proposed a permit limit based on controlling SO_2 emissions from a coal containing 0.75% sulfur."

From Figures 2 and 3 (Sargent & Lundy, Technical Memorandum, December 18, 2003), we can see that the average sulfur content increased from approximately 0.55% to 0.75% for Intermountain and from approximately 0.45% to 0.75% for Hunter. The standard deviation increased from approximately 0.25% to 0.30% and from approximately 0.05% to 0.40%, respectively. Based on all available information, we believe that a sulfur content of 0.75% is a reasonable estimate.

Comment #22

> "Emission estimates for sulfuric acid mist appear inconsistent between IPP Units 1, 2 and 3." (EPA, p.7)

Response

The average **actual** H_2SO_4 emissions for Units #1 & #2 over the 2-year baseline period was 0.49 lb/hr. The **estimated** H_2SO_4 emissions for Unit #3 were calculated as 39.7 lb/hr based on

conservative but commonly accepted assumptions. These assumptions are: 1% of the flue gas SO_2 will oxidize to SO_3 in the boiler, 1.2% will convert across the SCR and the overall H_2SO_4 removal efficiency of the fabric filter and the WFGD will be 90%.

Comment #23

> "The Approval Order must also specify a required SO_2 removal efficiency." (UWG, p.27)

Response

The comment is incorrect. Pursuant to R307-101-2, "BACT" is defined as "an emission limitation" that is "based on" the maximum degree of reductions in emissions. Accordingly, UDAQ has established two emission limitations representing BACT for SO_2 emissions from Unit #3. There is nothing in the applicable regulations to suggest that, in order to be lawful, the AO should actually specify the minimum control efficiency upon which the emission limitations are based.

See, also, the responses to Comments #19 and #20. We find that with these limits the IPP Unit 3 will not cause SO_2 increment violations at Capitol Reef National Park or excessive visibility impact at nearby Class I areas. (See also our response to Comments #68 and #69 for a more detailed discussion of these issues.) The commenter refers to an EPA Region VIII letter to the Montana Department of Environmental Quality regarding the Roundup Power Plant PSD permit (December 18, 2002). We quote from this letter (emphasis added):

> "BACT in terms of control efficiency. A minimum required SO_2 scrubber efficiency should be included in the permit, to ensure proper operation and maintenance of the scrubber, and to ensure that SO_2 emissions are minimized at all times, regardless of the sulfur content in the coal. **Because of the severe visibility impacts** identified by the Federal Land Managers, we believe the permit should specify scrubber efficiency in the range of 94% to 96% ...."

The reason for this comment appears to be "the severe visibility impacts" of the Roundup Power Plant. That is not the case for the IPP Unit 3.

Comment #24

> "IPP Unit 3 must be designed with sufficient capacity in its SO_2 controls such that no bypass will occur." (UWG, p.27)

Response

To the extent that the comment suggests that the AO, in order to be lawful, must include an equipment design or work practice requirement in addition to the limits on the SO_2 emission rate, the comment is incorrect. Pursuant to R307-101-2, "BACT" is defined primarily as an emission limitation and UDAQ has established two emission limitations representing BACT for SO_2 from Unit #3. An additional equipment design requirement would be redundant and unnecessary.

However, as a note, UDAQ finds that the IPP Unit 3 is being designed such that no bypass of the WFGD will occur under either normal or extraordinary operating conditions.

Comment #25

"The planned NO_x control systems can achieve lower emission rates." (UWG, p.28)

Response

UDAQ has reconsidered the NO_x emission limit in light of the additional information provided by the commenters. However, we find that the NO_x emission limit was properly set at 0.07 lb/MMBtu on a 30-day average. At this point in time, this is the most stringent NO_x limit, that we are aware of, imposed by any permit, granted or pending, on pulverized coal-fired boilers in the U.S.A.

Each of the documents cited by the commenter provides information on design control efficiency levels or other similar values; none presents any data indicting that a NO_x emission limitation more stringent than 0.07 lb/MMBtu on a 30-day average has been demonstrated to be achievable continuously. Thus, these documents are of no value in the BACT analysis except for general information.

Comment #26

"NO_x Control" (NPS, p.4)

Response

The permit applications cited by the commenter are for facilities that do not currently, and may not ever, exist. Neither permit application presents any data indicating that a NO_x emission limitation more stringent than 0.07 lb/MMBtu on a 30-day average has been demonstrated to be achievable continuously. Thus these documents are of no value in the BACT analysis except for general information. See, also, the response to Comment #25 above.

The NO_x emission limit of 0.07 lb/MMBtu for a 30-day averaging period is part of the BACT analysis. However, the emission limit of 633.5 lb/hr for 24-hour averaging period is provided for NAAQS, PSD increments, and Nonattainment Area impacts. It is enforceable and consistent with the BACT emission limit for a 30-day averaging period but it is not a result of the BACT analysis.

Comment #27

"The NO_x BACT limit must apply on a 24-hour basis." (UWG, p.29)

Response

The comment is incorrect. There is nothing in the applicable regulations indicating that the averaging period for the BACT emission limitations must be consistent with the averaging period for emission rates used in the visibility impacts analysis. The permit includes an enforceable NOx emission limitation, expressed on a 24-hour average basis, reflecting the emission rate used in the visibility impacts analysis.

This is consistent with the EPA memo of November 24, 1986, cited by the commenter. We quote (emphasis added):

> "In the case of sulfur dioxide (SO2), source compliance with the 30-day rolling average emission limit under subpart D(a) does not adequately demonstrate compliance with the short-term NAAQS and PSD increments. Consequently, **enforceable** limits pertaining to the performance of the flue gas desulfurization system on a short-term basis must also be established. Note, however, that the **short-term limits can result from either BACT analysis or the need to protect air quality.**"

See, also, the response to Comment #26 above.

Comment #28

> "The PM_{10} limit is not reflective of the maximum reductions achievable." (UWG, p.29)

Response

UDAQ has reconsidered both the filterable PM_{10} and the total filterable PM emission limits in light of the additional information provided by commenters. We have also requested and obtained additional information from IPP. Based on all additional information, UDAQ has established more stringent PM_{10} emission limits on the IPP Unit 3. The following limits will be in the AO:

0.012 lb/MMBtu for the filterable PM_{10} and
0.013 lb/MMBtu for the total filterable PM.

These are the most stringent filterable PM_{10} and total filterable PM emission limits, that we are aware of at this point in time, imposed by any permit, granted or pending, for pulverized coal-fired boilers in the U.S.A.

Comment #29

> "PM Control" (NPS, p.4)

Response

See the response to Comment #28 above.

The commenter quotes the emission limit of 0.0088 lb/MMBtu for the Northampton Generating station. The Northampton facility is a circulating fluidized-bed boiler burning anthracite culms; it is not a similar source burning similar fuel. Two cyclones return a very high percentage of fly-ash and unburned carbon to the furnace. Emissions of PM are further controlled by fabric filters. The same control technology is proposed for the IPP Unit 3.

The total PM_{10} value of 221 lb/hr, filterable and condensable, is provided for NAAQS, PSD increments, and Nonattainment Area impacts; it is not a result of the BACT analysis. We have selected the most stringent limit of 0.012 lb/MMBtu for the filterable PM_{10}. The condensable PM_{10} limit, calculated from the BACT/MACT emission limits for H_2SO_4, HCL and HF, is 0.009 lb/MMBtu. Based on all available information, UDAQ finds that these limits are appropriate.

The statements made in the paper cited by the commenter are opinions and not commercial offers backed-up by guaranties. Thus, they are not properly part of BACT analysis except for general information.

Comment #30

"BACT for filterable PM_{10} should be more stringent." (EPA, p.2)

Response

Please see the response to Comments #28 and #29.

Comment #31

"BACT emission limits for total PM_{10}, CO and NO_x should be in lb/MMBtu, not just lb/hr." (EPA, p.3)

Response

UDAQ has considered this comment and found the following:

- The CO emission limit on a 30-day rolling average is indeed a BACT emission limit and should be provided in lb/MMBtu. The appropriate value of 0.15 lb/MMBtu will be in the AO.
- The filterable and condensable PM10 emission limit on a 24-hour block average, the CO emission limit on an 8-hour rolling average, and the NOx- emission limit on a 24-hour block average are provided for NAAQS, PSD increments, and Nonattainment Area impacts; the values are appropriately given in lb/hr.

We have also reviewed the recent permits for coal-fired boilers and found that this is the common practice. The BACT emission limits are given in lb/MMBtu and the emission limits for NAAQS, PSD increments, and Nonattainment Area impacts are usually given in lb/hr.

Comment #32

Continuous Emission Monitor for PM_{10}. (NPS, p.8 and EPA, p.7)

Response

UDAQ has reconsidered the issue of PM CEMS in light of the additional information provided by the commenters. We have also requested and obtained additional information from IPP and others. Based on all available information, UDAQ believes that PM CEMS are still not advanced enough to provide reliable and accurate data at a reasonable cost. Regardless, UDAQ conducted further inquiry into this issue by contacting three sources that were represented as having working CEMs. These sources, Tampa Electric, Virginia Electric Power and Eli Lilly Pharmaceutical, were each contacted with the following general responses: Tampa Electric indicated that they had submitted a report to the EPA that essentially said that the CEM they had been using for the past two years did **not** meet the requirements of PS-11. The Florida DEP and Region IV indicated that they had not yet reviewed the report; EPA's OAQPS is currently reviewing the report and while there is indication from some that they disagree with the conclusions of the report, a response has not been issued. Virginia Electric Power indicated that they were required to install a CEM device as the result of a consent order but were unsure how they would be able to comply. They did intend to put two separate and redundant units on each of their two stacks (one a wet stack and one a dry) because they were not confident in the reliability of the CEM. Eli Lilly indicated that they had a working device from Switzerland that worked rather successfully for their specific application (i.e., narrow particle size distribution, non-variable flow rate, etc.); there is considerable concern that due to the broader size distribution of the PM and the variable flow rate

that this unit would not be appropriate for IPP – a device of this type has not been used in this type of application before. As stated above, UDAQ believes that, at the current time, PM CEMS are neither reliable nor accurate for the specific circumstances that this approval order is addressing. Additional discussion is available in the IPP response to this comment and the letter of June 9, 2004 from Deseret Power to EPA-Region 8.

Comment #33

> "UDAQ must include a visible emissions standard reflective of BACT." (UWG, p.30)

Response

UDAQ included visible emissions standards in the ITA: for all the baghouse stacks 10% opacity and for all the other points 20% opacity. These standards will be in the AO. In addition, a visible emissions standard reflective of BACT for the main boiler stack of 10% opacity will be included in the AO.

Comment #34

> "UDAQ did not properly analyze the cost effectiveness of use of a wet ESP to achieve a lower sulfuric acid mist emission rate." (UWG, p.31)

Response

UDAQ found that the technical feasibility of a wet ESP for control of H_2SO_4 emissions for IPP Unit #3 is questionable (see the Modified Source Plan Review pages 113 to 120). However, we have reconsidered the cost effectiveness of the wet ESP in light of the comment. The average cost effectiveness of a fabric filter (FF) and a wet FGD (WFGD), calculated as suggested by the commenter is $904 per ton of H_2SO_4 emissions removed (based on 1,610 tons/yr removed). The average cost effectiveness of the wet ESP plus the FF and the WFGD is $8,938 per ton of H_2SO_4 emissions removed (based on 1,749 tons/yr removed). The cost for each control option (FF + WFGD & WESP + FF + WFGD) is $1,455,440 and $15,632,562 per year, respectively. The incremental cost effectiveness of going from the FF and WFGD to the use of the wet ESP plus the FF and WFGD is thus $101,994 per ton removed [($15,632,562 - $1,455,440) ÷ (1,749 tpy – 1,610 tpy)] for the additional 139 tons/yr removed. UDAQ found that the wet ESP is not only technically questionable but is cost prohibitive as well. Furthermore, the impact on visibility from the H_2SO_4 emissions controlled by the FF and the WFGD without the WESP is only about 2% and will not cause an adverse impact on visibility. No perceptible impact on stack opacity is expected either at the H_2SO_4 concentration of 1.5 ppmdv (without the wet ESP) or less expected at the stack.

Comment #35

> "BACT emission limits must apply at all times, including periods of startup, shutdown and malfunction." (EPA, p.3 and UWG, p.32)

Response

UDAQ has reconsidered the issue in light of the comments. The BACT emission limits for IPP Unit 3 will be restated in the AO.

Comment #36

> "Explanation needed on how discussion of case-specific MACT determination led to the mercury emission limit proposed in the ITA." (EPA, p.5)

Response

The discussion of "Case-by-case MACT for Mercury" on pages 138 to 151 of the "UDAQ Modified Source Plan Review" is based on the best level of mercury control achieved in practice by similar utility scale PC-fired boilers burning western bituminous coals. However, UDAQ decided to use the more stringent emission limit proposed by EPA (69 FR 4720 Jan 30, 2004) as indicated on pages 151, 152 and 164 of the "UDAQ Modified Source Plan Review". UDAQ accepted the EPA conclusion on the best level of mercury control achieved in practice by similar utility scale boilers burning bituminous coals; thus, limiting to PC-fired boilers and western bituminous coals was not accepted. The EPA approach resulted in a wider pool of similar boilers and a more stringent emission limit. UDAQ believes that this emission limit is achievable in practice.

The requirement in 40 CFR 63.43(d)(1) that the limit "not be less stringent than the emission control which is achieved in practice by the best controlled similar source , as determined by the permitting authority" is satisfied as demonstrated by reference to the EPA proposed rule (69 FR 4666 & 4678 Jan 30, 2004) and the related background documents in the EPA dockets (Docket ID No.OAR-2002-0056 and Docket ID No.A-92-55).

Comment #37

> "Case-specific MACT determination for mercury should be expressed as an emission limit rather than just "a rate"." (EPA, p.5)

Response

We agree with EPA that the header in Condition 12 of the ITA should be re-titled "limit".

Comment #38

> "UDAQ failed to impose an enforceable mercury emission limitation as MACT." (UWG, p.36)

Response

See the response to Comment #36 above.

UDAQ properly proposed an enforceable mercury emission limit in the ITA (Condition 12), as discussed on pages 151, 152 and 164 of the "UDAQ Modified Source Plan Review". We did not propose using SO_2 and PM emission limits as surrogates for meeting the mercury limit.

UDAQ included testing, monitoring, record keeping and reporting requirements consistent with 40 CFR §63.43(g)(2) and 40 CFR §70.6(c) and, by reference, with the EPA proposed rule (69 FR 4652 Jan 30, 2004). See pages 151, 152 and 164 of the "UDAQ Modified Source Plan Review" and Condition 12 of the ITA.

An enforceable mercury emission limit as well as appropriate testing, monitoring, record keeping and reporting requirements will also be included in the AO.

Comment #39

> "The ITA fails to ensure compliance with case-by-case MACT requirements." (UWG, p.32)

Response

See the response to Comments #36, #40, and #41.

Comment #40

> "UDAQ failed to adequately determine the level of mercury control achieved by the best controlled similar source." (UWG, p.33)

Response

Please see the response to Comment #36.

We agree with the commenter that effective mercury controls are available for all coal-fired utility boilers; however, their efficiencies depend on the type of coal burned. This conclusion is amply supported by data. Please see the EPA proposed rule (69 FR 4666 Jan 30, 2004) and the related background documents in the EPA dockets (Docket ID No.OAR-2002-0056 and Docket ID No.A-92-55) (emphasis added).

> *"The EPA found that each of the best-performing units had a combination of factors that was the basis for the better performance on that particular unit. The factors identified included the **Hg and chlorine (Cl)** contents of the coal, the **speciation of the Hg** in the flue gas stream, and the control device configuration."*

The mercury emission speciation testing, for example, revealed that the particulate-bound mercury percentages were greatly dependent on coal rank. The averages were:

Bituminous coal	44.49%
Subbituminous coal	22.97%
Lignite	17.09%
Coal refuse	99.31%

The particulate-bound mercury is efficiently removed in some control devices such as fabric filters. Thus, their efficiencies depend greatly on coal rank.

The Kline Township Cogen boiler, referred to by the commenter, burns coal refuse. It does not belong to the subcategory of bituminous coal-fired units by the EPA proposed rule. We believe that this subcategorization is justified as elaborated above. Thus, the Kline Township Cogen boiler was not considered. We mention though that the particulate-bound mercury percentage measured for this unit was 99.02%.This explains the high efficiency of the fabric filters installed at the Kline Township facility.

The Mecklenburg Cogeneration facility, also referred to by the commenter, has an average emission rate of 0.1062 lb/TBtu. However, the 97.5th percentile emission limit for this facility,

when an appropriate variability is added, is 1.8051 lb/TBtu. We prescribed a more stringent emission limit of 0.6094 lb/TBtu i.e. 6.0×10^{-6}/MWh.

Comment #41

> "UDAQ failed to evaluate and prescribe a mercury emission limitation reflective of the maximum degree of reduction in emissions of mercury that could be achieved." (UWG, p.37)

Response

UDAQ properly evaluated and prescribed a mercury emission limitation reflective of the maximum degree of reduction in emission of mercury that could be achieved taking into consideration the costs; this is referred to as MACT beyond-the-floor.

Based upon available information, as defined in 40 CFR §63.41, UDAQ found that such beyond-the-floor control technologies are not available and demonstrated. In this, UDAQ agrees with the EPA proposed rule (69 FR 4679 &4698 Jan 30, 2004):

> *"Once the MACT floor determinations were done for new units in each subcategory (by fuel type), EPA considered various regulatory options more stringent than the MACT floor level of control (i.e., additional technologies or work practices that could result in lower emissions) for the different subcategories. Due to the technical complexities of controlling metal HAP emissions from the sources affected by this rule, however, EPA has not been able to determine whether identified potential beyond-the-floor options are available and demonstrated.*
>
> *Research currently indicates that Hg control technologies other than FGD and SCR--most notably activated carbon injection (ACI) and breakthrough technologies (e.g., chemical systems to enhance removal efficiencies for wet scrubbers)--may one day allow facilities to reliably reduce Hg emissions to levels significantly below the levels achieved through application of FGD and SCR needed to satisfy SO2 and NOX control requirements. However, these technologies have not been adequately demonstrated on full-scale power plants."*

UDAQ identified and considered all potentially available control technologies. We did not find any such technology that we would consider actually available as a MACT beyond-the-floor, defined in 40 CFR §63.43(d)(2). The most promising one, activated carbon injection, is discussed in the "UDAQ Modified Source Plan Review".

Comment #42

> "UDAQ did not evaluate inherently lower emitting processes." (UWG, p.39)

Response

UDAQ did not find any inherently lower emitting process that is available. The commenter is specifically proposing IGCC. See also the response to Comment #12 above. However, IGCC is not a similar source to other coal-fired facilities as defined in 40 CFR §63.41 (emphasis added):

> *"Similar source means a stationary source or process that has comparable emissions and is* ***structurally similar in design and capacity*** *to a constructed or reconstructed major source such that the source could be controlled using the same control technology "*

The EPA proposed rule also finds that IGCC is a unique process different from other coal-fired processes (69 FR 4666 Jan 30, 2004):

> *"For the purposes of the proposed rule and based on the above information, the coal-fired units at existing affected sources are subcategorized into five subcategories, four based on coal rank and one based on process type: bituminous (including anthracite); subbituminous; lignite; coal refuse (which includes anthracite coal refuse (culm), bituminous coal refuse (gob), and subbituminous coal refuse); and IGCC (coal syngas).*
>
> *Integrated gasification combined cycle units combust a synthetic coal gas. No coal is directly combusted in the unit during operation (although a coal-derived fuel is fired), and, thus, IGCC units are a distinct class or type of boiler for the proposed rule."*

Therefore, IGCC facilities were not included in the pool of similar sources when determining the mercury MACT floor by 40 CFR §63.43(d)(1).

That IGCC is not a control technology is also generally understood. Thus, IGCC facilities were not included in the pool of control technologies potentially available for the mercury MACT beyond-the-floor.

Comment #43

> "Use of sorbent injection for mercury control should have been thoroughly evaluated." (UWG, p.39)

Response

UDAQ thoroughly evaluated use of sorbent injection, such as activated carbon, for mercury control. We considered activated carbon injection on pages 138 and 142 and on page 152 by reference to the EPA proposed rule. The following quotes are from the EPA proposed rule (69 FR 4676&4673 Jan 30, 2004):

> *" Although AC, chemically-impregnated AC, and other sorbents show potential for improving Hg removal by conventional PM and SO2 controls, this technology is not currently available on a commercial basis and has not been installed, except on a demonstration basis, on any electric utility unit in the U.S. to date. Further, no long-term (e.g., longer than a few days) data are available to indicate the performance of this technology on all representative coal ranks or on a significant number of different power plant configurations. Therefore, we do not believe these technologies provide a viable basis for going beyond-the-floor.*
>
> *Some have argued that the experience gained from regulation of Municipal Waste Combustors and Health, Medical and Infectious Waste Incinerators in the early 1990s indicates that coal-fired power plants should be able to achieve 90*

percent Hg emission reductions (see "Out of Control and Close to Home: Mercury Pollution from Power Plants." Environmental Defense. 2003) The EPA expects that some Utility Units can achieve such high reduction rates, depending on factors such as the Hg and Cl content of different coals, as outlined above. However, there are important technical differences between Utility Units and municipal waste combustors and health, medical and infectious waste incinerators. Consequently, EPA believes 90 percent emission reductions cannot be achieved across all Utility Units in the proposed section 112 time frame."

Regarding the referenced MidAmerican facility, there are several significant facts that must be considered:

- The coal to be burned is subbituminous;
- The expected control efficiency without activated carbon injection is only 34%;
- The expected control efficiency even with activated carbon injection is still only 70% or 83%, depending on interpretation;
- The Iowa Department of Natural Resources (IDNR) imposed a mercury emission limit of 1.7 lb/TBtu i.e. 16.7 x 10-6 lb/MWh.

UDAQ, on the other hand accepted the EPA proposed rule; the best controlled source is the Stockton facility:

- Bituminous coal is burned;
- The measured control efficiency without activated carbon is 92%;
- Activated carbon injection is not installed;
- A 97.5th percentile emission limit is 0.61 lb/TBtu i.e. 6.0 x 10-6 lb/MWh.

Additionally, both MidAmerican and IDNR consider activated carbon injection experimental as evidenced from their comment and response (IDNR Response to Public Comments, July 17, 2003, pages 6 and 7).

MidAmerican comment:

> "However, because a PAC system is still considered experimental for achieving mercury reductions, MidAmerican believe it is appropriate that testing and optimization of the system define the final emission limit for mercury."

IDNR response:

> "This limit will be reviewed along with the results of the optimization study as noted in condition 14.M.(6)."

The commenter also states:

> "Indeed, the website of the company that performed all of the full-scale studies of sorbent injection at coal-fired power plants, ADA-ES, indicates that sorbent injection is "proven technology' that "works for all coal plants and configurations," is "cost effective" and "available now"."

This statement means nothing beyond the fact that this technology is available for sale. It does not show that this control technology is available in the sense of 40 CFR §63.43(d)(2) i.e. with acceptable cost and risk.

In addition, the cost analysis presented in this comment overlooks an important aspect: the risk involved in installing a control technology that "*has not been installed, except on a demonstration basis, on any electric utility unit in the U.S. to date. Further, no long-term (e.g., longer than a few days) data are available to indicate the performance of this technology on all representative coal*

ranks or on a significant number of different power plant configurations" (69 FR 4676 Jan 30, 2004).

In summary, UDAQ thoroughly evaluated sorbent injection as an option for controlling mercury to the maximum extent at IPP Unit 3. "Additional cooling" was only one of the reasons for dismissing activated carbon injection, as demonstrated above. UDAQ prescribed a substantially more stringent emission limit proposed by EPA of 0.61 lb/TBtu i.e. 6.0×10^{-6} lb/MWh.

Comment #44

> "UDAQ should have evaluated use of K-fuels at IPP unit 3." (UWG, p.41)

Response

See the response to Comment #17. UDAQ evaluated the use of K-fuels at IPP unit 3 by reference to the EPA proposed rule. The following quotes are from the EPA proposed rule (69 FR 4677 & 4678 Jan 30, 2004).

> *"As was the case for existing units, in developing a MACT strategy for new units, EPA considered several prevention measures as an alternative to the application of Hg and Ni control technology. These measures were the same precombustion techniques evaluated for existing units, which included fuel substitution, process changes, and work practices.*
>
> *For these reasons, EPA decided that mandated fuel type is not an appropriate criterion for identifying the MACT level of control for new coal-fired units. In any event, we do not believe that we can or should prescribe a given fuel type because of the implications on electricity reliability, energy security, etc "*

Other mercury control technologies such as electro catalytic oxidation and advanced dry FGD all have limited commercial experience on coal-fired utility boilers. UDAQ does not consider them available for the mercury MACT beyond-the-floor.

Comment #45

> "UDAQ failed to meet the case-by-case MACT requirements for other HAPs." (UWG, p.42)

Response

UDAQ met all of the case-by-case MACT requirements for other HAPs to be emitted by IPP Unit 3. In particular, UDAQ set the MACT floor; we also considered MACT beyond-the-floor; and we set enforceable emission limitations for mercury. However, we, like EPA, decided not to promulgate standards for emissions of non-mercury pollutants (69 FR 4656&4659 Jan 30, 2004):

> *"As for the other non-Hg and non-Ni metallic HAP examined, EPA made the following conclusions. With regard to arsenic, a metal, EPA concluded that there were several uncertainties associated with both the cancer risk estimates from arsenic and the health effects data for arsenic, and that further analyses were needed to characterize the risks posed by arsenic emissions from Utility Units*

(ES at 21). As to lead and cadmium, which are also metals, EPA found that the emission quantities and inhalation risks of these HAP were low and did not warrant further evaluation (ES at 24). ***As for the remaining, non-Hg, non-Ni metallic HAP, EPA found that such pollutants posed no hazards to public health.***

The EPA also examined HCl and HF, which are inorganic or acid gas HAP, and found ***no exceedances of the health benchmark for either substance*** *(ES at 24). As for dioxins, organic HAP, EPA concluded that the quantitative exposure and risk results for such* HAP *"***d*(id) not conclusively demonstrate the existence of health risks of concern associated with exposures to utility emissions either on a national scale or from any actual individual*** **utility.***" (Utility RTC at 11-5.) Finally, EPA concluded that emissions from Utility Units of* ***the remaining HAP examined in the Study did not appear to be a concern for public health*** *(65 FR 79827).*

In the circumstances presented here, and as discussed below, EPA interprets section 112(n)(1)(A) only to authorize the Agency to promulgate section 112 standards for Utility Units with respect to HAP emissions from such units that are reasonably anticipated to result in a hazard to public health after imposition of the other requirements of the CAA. To the extent section 112 can be interpreted as authorizing but not requiring EPA to go beyond that, and to promulgate section 112 standards for HAP emissions that are not reasonably anticipated to result in a hazard to public health, EPA has decided not to do so."

UDAQ also looked at a different approach based on 40 CFR §63.43(d)(3):

"The applicant may recommend a specific design, equipment, work practice, or operational standard, or a combination thereof, and the permitting authority may approve such a standard if the permitting authority specifically determines that it is ***not feasible*** *to prescribe or enforce an emission limitation under the criteria set forth in section 112(h)(2) of the Act.*

[112(h)(2) ***Definition.*** *— For the purpose of this subsection, the phrase "not feasible to prescribe or enforce an emission standard' means any situation in which the Administrator determines that—... (B) the application of measurement methodology to a particular class of sources is not practicable* ***due to technological and economic limitations.]*** *"*

UDAQ found that it was not practical to impose emission limits directly due to technological and economic limitations of measurement methodology. A practical alternative is the use of surrogates (State and Local Air Pollution Control Officials Recommendations for Utility MACT Standards, Utility MACT Workgroup Meeting, October 22, 2002):

"One practical way to address the large number of non-mercury HAPs emitted by coal-fired boilers is through the use of surrogates. Surrogates may be non-HAPs (for example, CO or PM2.5 mass) or a single HAP that is representative of many HAPs. This approach is useful to efficiently and effectively address the majority of HAPs emitted by coal-fired plants.

A surrogate is useful if efforts to minimize the surrogate also result in the minimization of a group of HAPS which have common air pollution control

properties. Under section 112(d) of the CAA, the Administrator is directed to use emission information to set MACT limits. The Administrator is not limited to using only HAP emission information, and it is reasonable to conclude the Administrator may also use information on other emissions which are associated with HAPs emissions. A surrogate is particularly useful if it can be continuously monitored and serve as a continuous indicator of HAP emissions."

Precedent was provided by EPA in establishing MACT standards for several categories of sources emitting non-mercury HAP metals (66 FR 36835, July 13, 2001):

"For the proposed rule, we decided that it is not practical to establish individual standards for each specific type of metallic HAP that could be present in the various processes (e.g, separate standards for manganese emissions, separate standards for lead emissions, and so forth for each of the metals listed as HAP and potentially could be present) When released, each of the metallic HAP compounds behaves as PM. As a result, strong correlation exists between air emissions of PM and emissions of the individual metallic HAP compounds. The control technologies used for the control of PM emissions achieve comparable levels of performance on metallic HAP emissions. Therefore, standards requiring good control of PM will also achieve good control of metallic HAP emissions. Therefore, we decided to establish standards for total PM as a surrogate pollutant for the individual types of metallic HAP. In addition, establishing separate standards for each individual type of metallic HAP would impose costly and significantly more complex compliance and monitoring requirements and achieve little, if any, HAP emissions reductions beyond what would be achieved using the surrogate pollutant approach based on total PM."

This approach was considered for the IPP Unit 3 on pages 136 to 140 and page 151 of the "UDAQ Modified Source Plan Review". The BACT emission limits for surrogate pollutants, PM, SO_2, and CO, were shown to be the appropriate MACT emission limits for non-mercury HAPs. The enforceable emission limitations were formulated on page 151 through the emission limitations of the surrogate pollutants. However, UDAQ, like EPA, decided not to promulgate standards for emissions of non-mercury pollutants.

Comment #46

"Reducing Emissions from IPP Units 1 and 2" (NPS, p.14)

Response

UDAQ welcomes NPS suggestions and support. However, this issue is not part of the present project out for comment.

Comment #47

"We strongly support UDAQ in using differential pressure as a permit condition due to the fact that we have shown that the use of differential pressure is equivalent to a grain loading method of determining emissions and we appreciate the flexibility that UDAQ is extending here." (IPSC/IPA, p.3)

Response

The comment was noted. As no technical issue was raised with respect to the ITA, no changes were made to the AO.

Comment #48

> "The mercury emission rate in Condition 12 is 6.0×10^{-6} lb/MMBtu. This number should reflect the complete proposed MACT rate for mixed blends of bituminous (6×10^{-6} lb/MWh) and subbituminous coals (20×10^{-6} lb/MWh). Please revise this mercury limit to range between 6×10^{-6} lb/MWh and 20×10^{-6} lb/MWh proportional to the fuel blend ratio to allow us to burn this range of coals. The MACT utilizes a calculation based upon the blend ratio." (IPSC/IPA, p.3)

Response

The AO will include the appropriate statement to reflect the proposed MACT rule for mercury.

Comment #49

> "The opacity limit of 20% for fugitive dust sources is not required under any state requirement, and the fugitive dust control plan required in Condition 16 should be the basis for BACT. Please remove the second paragraph of Condition 16 with 20% opacity limit." (IPSC/IPA, p.3)

Response

The opacity limit of 20% for visible fugitive dust emissions from haul-road traffic and mobile equipment is the result of the BACT analysis. No changes were made to the AO.

State of Utah

Department of
Environmental Quality

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DIVISION OF AIR QUALITY
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Director

OLENE S. WALKER
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GAYLE F. McKEACHNIE
Lieutenant Governor

DAQP-085-04

MEMORANDUM

TO: Intermountain Power Service Corporation (IPSC) File (N327010)

THROUGH: Cheryl Heying, Manager, Planning Branch

THROUGH: Brock LeBaron, Manager, Technical Analysis Section BL

FROM: Tom Orth, Air Quality Modeler

DATE: October 15, 2004

SUBJECT: Technical Analysis' response to comments received on IPSC's Intent to Approve number DAQE-IN327010-04

On April 1, 2004, a public comment period began to solicit comments on the Intent to Approve (ITA) Intermountain Power Service, Corporation's (IPSC) addition of a new Unit 3 at their existing Intermountain Power Plant (IPP), located in Delta, Millard County, Utah.

Numerous comments were received during the comment period and at the public hearing. All comments received during the public hearing and the two public comment periods pertaining to the Air Quality Impact Analysis (AQIA) are listed here, with the original comments being included as an attachment. Following each comment is the Utah Division of Air Quality's (UDAQ) response, along with any action taken by the Division in regards to the final Approval Order (AO).

Quoted items are taken verbatim from the original comment submission. If the comment was unclear, UDAQ attempted to explain the comment as understood by the Division. Public comments addressed in this document represent a paraphrasing of the originally submitted comment. Readers should refer to the attached original comments for the full text of the comment.

The UDAQ responded to the attached comments made during the public comment periods (PCP) from April 1, 2004 to May 21, 2004, from June 3, 2004 to July 3, 2004, and the public hearing of April 29, 2004.

TO/gw

Attachment

Responses to EPA's May 24, 2004, comment letter on the addition of IPP - Unit 3

Comment 1: Short-term Emission Rate (pg 5, p3)

Maximum short-term emission rates should be used in modeling for consumption of short-term PSD increment. The PSD Class I increment analysis does not appear to have included appropriate emission rates from increment consuming sources in the area and as a result, cumulative increment consumption in the Class 1 areas may have been underestimated.

Response:

The EPA suggests that the Acid Rain Continuous Emissions Monitoring (CEM) data might be appropriate to use in an increment analysis. UDAQ examined this possibility during the initial review of the permit application and found it to be troubling. Increment consumption for existing sources should be based on actual changes in emissions since the baseline date. CEM data includes the substitution of artificially inflated maximum hourly emission rate for periods when the CEM was offline, in order to meet the requirements of the Acid Rain emissions credit portion of the program. If, as EPA has suggested, actual short-term CEM data were to be used in the analysis, hourly emission should then be paired in time and space with actual hourly weather data to verify that the increment violation would likely have occurred.

At the time IPA established its Class I and AQRV modeling methodology with the NPS and UDAQ, the 1996 MM5 data set was the acceptable meteorological data set for modeling Class I and AQRV impact in the US. This one-year data set met IPA's legal requirement for long-range transport modeling at the time the methodology was developed. PSD modeling guidance further requires that estimates of actual emissions for existing sources be based on the most current two-year period representing normal operations at the facility. In the case of IPP, that period was 2000 through 2001. Since the emissions data could not be paired in time and space with the meteorology, the UDAQ elected to allow the use of an emission methodology that better represented normal operations at the facilities, and would result in concentration estimates in the Class I areas that had a higher statistical probability of actually occurring. The UDAQ believes that the increment consumption methodology used in the analysis meets the requirements of the Clean Air Act, and that no further Class I increment modeling for this permit action is warranted.

Comment 2: Meteorological Data (pg 6, p4)

IPP's modeling analysis included only one year (1996) of prognostic meteorological data. If the State is "grandfathering" the previous 1-year data requirement for this source, the basis for it should be stated.

Response:

The UDAQ did not "grandfather" the data requirement; it followed applicable rules. On April 15, 2003, the EPA published a Federal Register notice adopting revisions to the Guidelines on Air Quality Models, changing the previous requirement for one year of mesoscale meteorological (MM5) data to simulate long-range transport to three years of data. On May 13, 2003, EPA published a correction to this notice, making the effective data for the three-year meteorological data requirement April 15, 2004. The IPA modeling was considered complete before the April 15, 2004 deadline passed. Conversations with EPA Region VIII meteorologist, Kevin Golden, confirmed their policy that the uses of the most current guidance requirements have practical limitations. A permitting source should not have to model two additional years if the original analysis has been performed, and found to be complete before the effective date of the rule. Based on this, the UDAQ feels IPA has met the legal requirements for MM5 meteorological data usage at the time the modeling was deemed complete.

Comment 3: Modeling Data Archives (pg 6, p5)

There have been revisions to the project that may not be reflected in the modeling archives. Any updates or revisions to the modeling that have already been made, or will be made in response to comments, should be provided to EPA.

Response:

The UDAQ submitted additional modeling files as they were received.

Comment 4: Overlapping Energy Projects (pg 6, 6)

EPA recommends an analysis of any potentially overlapping ambient impacts of the large energy projects in Utah for which permits are simultaneously pending. This includes NEVCO, and PacifiCorp - Currant Creek.

Response:

The two above-mentioned energy projects were not required to be included in the IPP analysis at the time the modeling protocol was approved since their applications were not complete at that time. In addition, since NEVCO and Currant Creek's impacts on all Class I areas are below the Class I SIL for all pollutants, it is not expected that their contribution would result in a Class I increment violation when added to IPA and other increment consuming source impacts. This same argument applies to other ongoing energy projects that have submitted applications since the modeling for IPP was approved by the UDAQ.

Responses to NPS's May 27, 2004 comment letter on the addition of IPP - Unit 3

Comment 1: 3-Hour SO_2 Limit (pg 8, p3)

We recommend that the UDAQ also include a 3-hour SO2 limit in the ITA.

Response:

The UDAQ is including a 3-hour SO_2 limit in the final AO.

Comment 2: Short-term Emission rates (pg 8, p4)

Based on EPA guidance, to help ensure compliance with short-term increments, the highest actual 3-hour or 24-hr average emissions during the last two years of operation should apply to the 12 other sources in this analysis. See also the response to the Environmental Groups' Comments #19.

Response:

The UDAQ policy for determining short-term emission rates for PSD increment consumption is to use annual average emissions divided by hours of operation. This is used for all emissions sources that are constructed and currently operating.

Comment 3: Increment Status of PacifiCorp – Hunter Unit 1 (pg 9, p3)

IPA did not include Hunter Unit#1 in its increment inventory.

Response:

The UDAQ does not interpret Hunter Unit 1 as consuming increment, since the unit has not been modified since the Major source baseline date and was in operation at the time the baseline concentration was established (i.e. major source baseline date).

Comment 4: Inclusion of Other Energy Projects (pg 9, p3)

Emissions from the recently permitted NEVCO Sevier draft permit are not included in the IPA cumulative increment analysis.

Response:

The UDAQ did not require that NEVCO be included in the IPP analysis at the time the modeling protocol was approved since the NEVCO application was not complete at that time. In addition, since NEVCO's impacts on all Class I areas are below the Class I SIL for all pollutants, it is not expected that their contribution would result in a Class I increment violation when added to IPA and other increment consuming source impacts. This same argument applies to other ongoing energy projects, which have submitted applications since the modeling for IPP was approved by the UDAQ.

Comment 5: Ammonia Monitoring (pg 12, p2, and pg 2 of cover letter)

We recommend that Utah collect ambient ammonia data or ask that permit applicants contribute to monitoring so that future modeling can better account for this variable.

Response:

Ammonia is not a federally regulated air contaminant. Therefore, the UDAQ does not have the authority to require a permitting source to collect ambient ammonia data.

Comment 6: Mitigation of Cumulative Impacts (pg 14 p 3 and pg 2 of cover letter)

We recommend consideration of additional strategies to mitigate the cumulative emission increases and visibility impacts before issuing a permit, as a prudent approach to safeguarding Utah's outstanding visibility and night skies.

Response:

The UDAQ does not feel that they have the authority to require IPP to reduce emissions since the NPS has determined that IPP unit 3 does not cause an adverse impact on visibility.

Responses to NPS's March 25, 2004 comment letter on the addition of IPP - Unit 3

Comment 1: Additional Years of Class I Impact Modeling (pg 8, p2)

In order for the Federal Land Manager to have a more informed decision regarding IPP-3's impacts at the five Class I parks in the region, we ask that IPA run CALPUFF using meteorological data for 1990 and 1992, and report those results to us.

Response:

On April 15, 2003, the EPA published a Federal Register notice adopting revisions to the Guidelines on Air Quality Models, changing the previous requirement for one year of mesoscale meteorological (MM5) data to simulate long-range transport to three years of data. On May 13, 2003, EPA published a correction to this notice, making the effective data for the three-year meteorological data requirement April 15, 2004. The IPA modeling was considered complete well before the April 15, 2004 deadline passed. Based on this, the UDAQ feels IPA has met the legal requirements for MM5 meteorological data usage at the time the modeling was deemed complete, and has no legal authority to require additional years in the analysis.

Responses to Environmental Groups' May 20, 2004 comment letter on the addition of IPP - Unit 3

Comment 1: Cooling Tower Emissions (pg 31, p4)

IPSC relied on a paper entitled *Calculating Realistic PM_{10} Emissions from Cooling Towers*, by J. Reisman and G. Frisbie in justifying a lower PM_{10} emission factor for the Unit 3 cooling tower. The emission rate is 1/3 that projected for Units 1 and 2. If Unit 3's cooling tower emissions were tripled, there would be exceedances of the PSD increment for PM_{10}. The Approval Order must include a PM_{10} emission limitation for the Unit 3 cooling towers. The permit must also require emissions testing insures continuous compliance with the cooling tower limit.

Response:

The UDAQ has evaluated the affect of tripling the emission rate and has determined that the impacts from the cooling towers are in a different location than the maximum impacts from the other fugitive sources. The PSD increment would not be threatened by tripling the emission rate for the Unit 3 cooling towers. Hence, a separate emission limit for the cooling towers to protect the PM_{10} increment is not warranted.

Comment 2: Localized Soil and Vegetation Impact Analysis (pg 43, p3)

IPSC's permit application should be denied because it failed to provide a full and complete analysis of "the impairment to visibility, soils and vegetation", and because threshold sulfate deposition rates will be exceeded in Capitol Reef National Park. *See*, 40 C.F.R. § 52.21(o)(1) & (2) and/or 40 C.F.R. §51.166. *See also*, Utah Admin. Rule R307-405-6(2)(a)(i)(D).

Response:

IPA presented a soils and vegetation analysis in section 8.15 of their May 15, 2003 NOI. Their analysis indicated that nitrogen impacts would be less than the 5% of the foliar injury level (see Table 8-90). There were no comments from the public that indicated that their crops were being damaged from the existing Units 1 and 2, but instead all of the comments from local farmers indicated there were no impacts.

Comment 3: Growth Impact Analysis (pg 43, p4)

IPSC's PSD permit application failed to provide a thorough analysis of the "general commercial, residential, industrial and other growth associated with the source" as required by 40 C.F.R. 52.21(o)(1) & (2); Utah Admin.Rule R307-405-6(2)(a)(i)(D).

Response:

IPA presented an analysis on the impact of "general commercial, residential, industrial and other growth associated with the source" in section 8.14 of the NOI. IPA's analysis indicated that there would not be substantial growth to the area since most of the local industry and infrastructure necessary to support the plant and is already in place. The UDAQ is in agreement with IPA's conclusion.

Comment 4: Growth Impact Analysis (pg 43, p3)

IPSC must evaluate the short and long term impacts associated with this growth, including any air emissions from the residential housing units (i.e. any natural gas fired appliances).

Response:

New emissions resulting from the addition of residential housing units (either on-site or in the nearest community of Delta, Utah) will be small, and are not regulated under Utah Air Quality Rules. In the past, the UDAQ has evaluated the environmental impact of the average residential unit, or group of units, and has determined that their impact on air quality is minimal.

Comment 5: Growth Impact Analysis (pg 43, p3)

There will also be increased vehicular traffic to bring the increased amount of coal to the site. The increased traffic could cause violations of the 24-hour PM_{10} increment.

Response:

Coal for IPP Unit 3 will be hauled on site primarily using rail cars. The emissions from trains delivering coal to the plant will be quite small and were not considered in the modeling. Similarly, vehicular traffic will not be large (both delivery and on-site tail-pipe emissions) enough to impact the consumption of increment. Estimated emissions from these sources are in the 0.33 lb/hr range compared to a PM_{10} limit in the AO of 221 lb/hr.

Comment 6: Growth Impact Analysis (pg 43, p3)

IPSC's soils and vegetation discussion is inadequate. IPSC did not evaluate impacts on soils. IPSC's vegetation analysis is limited to emissions from the stack and does not consider "general commercial, residential, industrial and other growth associated with the source" as required by 40 C.F.R. 52.21(o)(1) and Utah Admin. Rule R307-405-6(2)(a)(i)(D). Further, the vegetation analysis fails to provide a meaningful analysis of other pollutants, such as ozone, mercury, and CO_2.

Response:

Significant changes to soils and vegetation impacts near IPA are not expected to occur since the majority of impacts from sulfur dioxide and nitrogen dioxide are several kilometers away, and very low compared to the secondary NAAQS. Impacts on soil and vegetation resulting from "general commercial, residential, industrial and other growth associated with the source" are not expected to increase significantly since most of the commercial, residential, industrial and other growth necessary to support the addition of Unit 3 are already in place. The UDAQ did not find any potential adverse impacts to soils and vegetation in its review of IPA's NOI. (See section 8.15 of the NOI).

Comment 7: Sulfur Deposition Rates (pg 44, p2)

Sulfate deposition rates in Capitol Reef National Park will exceed the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Deposition Analysis Threshold (DAT) based on emissions from Unit 3 alone. IPSC's permit application should be denied for this reason alone.

Response:

The NPS did mention the exceedance of the DAT in their March 25, 2004, comment letter to the UDAQ. However, there was no mention of a finding of adverse impacts to soils and vegetation in their comments, or in their May 27, 2004, final comment letter.

Comment 8: Cumulative Impacts (pg 44, p2)

IPSC's analysis must assess the cumulative impacts to soils and vegetation, as well as deposition rates, for all three IPP Units.

Response:

R307-405-6(2)(a)(i)(D) states the source shall provide "an analysis of the air quality related impact of the source or modification." The rule does not require a cumulative analysis of impacts to soils and vegetation.

Comment 9: Monitoring Requirements (pg 44, p3)

IPSC only conducted pre-construction monitoring for the nine-month period October 2001 through June 2002, avoiding the summer period entirely.

Response:

IPP did conduct a full year of concurrent meteorological, PM_{10}, and SO_2 monitoring during the period from October 1, 2001 thru September 28, 2002 (see Section 8.9.1 of May 14, 2003 NOI).

Comment 10: Cumulative Impacts (pg 44, p5)

In the far-field PM_{10} analysis, IPSC initially only analyzed the impacts from the new Unit 3. Emissions from Units 1 and 2 were not included in the analysis.

Response:

Utah and EPA regulations do not require the analysis of existing major sources other than the modification or new major source that is being permitted, unless the impacts from the modified source alone or new source trigger cumulative modeling requirements (i.e., Class I and II SILs). Utah County PM_{10} Non-attainment area impact modeling performed by IPA correctly followed the requirement of R307-403-5(1), which states " *New sources which have a potential to emit, or modified sources which would produce an emission increase equal to or exceeding the tonnage total of combined PM_{10}, sulfur dioxide, and oxides of nitrogen listed below which are located in or impact a PM_{10} Non-attainment Area as defined in (a) below, shall obtain an enforceable offset as defined in (b) and (c) below.*" IPA was only required to model the modified part of the source (i.e., the addition of Unit 3) in their analysis.

Comment 11: Changes to IPP Units 1 and 2 (pg 44, p5)

As discussed in the January 23, 2004, comment letter from Grand Canyon Trust and Sierra Club to UDAQ, it appears that the increases in capacity of IPP Units 1 and 2 authorized by UDAQ in 2002 may have been in violation of Utah permitting regulations.

Response:

The comment addresses existing units at IPP, and does not pertain to the permitting of IPA Unit 3.

Comment 12: Cumulative Impacts (pg 45, p3)

(PG 45) Visibility analyses conducted by the National Park Service greatly underscore the significance of not including IPP Units 1 and 2 in the visibility impacts modeling assessment. The Park Service modeled all three units at IPP and found "numerous days with impacts greater than a 10% change in extinction at all 5 Class I parks." The March 22, 2004 Modified Source Plan Review does not include any discussion of the Park Service's visibility analyses.

Response:

The analysis conducted by the NPS, as stated in their May 27, 2004 comment letter for IPP Unit 3, ultimately lead to the determination by the NPS that IPP Unit 3, "*would not cause an adverse impact on visibility (as defined in 40 CFR 51.301)*" in any of Utah's five Class I areas. The UDAQ concurs with this determination. The Unit 3 analysis performed by the NPS showed impacts less than 5% at all parks. The Federal Land Managers' Air Quality Related Values Workgroup (FLAG) guidance document for modeling visibility impacts from new or modifying sources states that a cumulative analysis is only required if the impact from the new or modifying source exceeds 5%. A maximum change of 4.26% was predicted at Capitol Reef National Park when the 1996 MM5 data was used.

Comment 13: Meteorological Data Requirements for Class I Analyses (pg 45, p5)

IPSC used only one year of mesoscale meteorological data in their far field modeling assessments. However, EPA's Guideline on Air Quality Models requires that at least three years of such data be used. See Section 9.3.1.2 of 40 C.F.R. Part 51, Appendix W.

Response:

On April 15, 2003, the EPA published a Federal Register notice adopting revisions to the Guidelines on Air Quality Models, changing the requirement for one year of mesoscale meteorological (MM5) data to

simulate long-range transport to three years of data. On May 13, 2003, EPA published a correction to this notice, making the effective date for the three-year meteorological data requirement April 15, 2004.

Additional modeling performed by IPA for the Class I CALPUFF analysis was received on a CD on June 19, 2003. Additional modeling for the Utah County CALPUFF analysis was received in July of 2003. No other modeling CDs were received after this date. The IPA modeling was considered complete well before the April 15, 2004 deadline passed. Conversations with EPA Region VIII meteorologist, Kevin Golden, confirmed their policy that the uses of the most current guidance requirements have practical limitations. A permitting source should not have to model two additional years if the original analysis has been performed, and found to be complete before the effective date of the rule. Based on this, the UDAQ feels IPA has met the legal requirements for MM5 meteorological data usage at the time the modeling was deemed complete.

Comment 14: PM_{10} Background Concentration (pg 47, p1)

The May 2003 NOI states that the second high monitored 24-hour value for PM_{10} was used to represent the background concentrations in the modeling analyses. However, no further information was given in the NOI or in UDAQ's March 22, 2004, Modified Source Plan Review regarding why the highest monitored value was not used.

Response:

The highest PM_{10} concentration monitored during the one-year monitoring period occurred during a summertime high wind event, where windblown dust was the main contributor to the concentration. The second-highest recorded value was collected under lighter winds than the first high measurements. Lower wind speeds are conducive to high-predicted ground level impacts in the computer model. Therefore, the use of the second highest monitored value coupled with the second highest impact predicted by the model (occurring during a period of low wind speed) provided the most accurate assessment of the worst potential impact of the proposed project.

Comment 15: Impacts on Non-Attainment Areas (pg 47, p3)

IPSC has failed to conduct an adequate modeling analysis to determine whether IPP's impacts in the Utah County PM_{10} non-attainment area would trigger the requirement for emission offsets under Utah regulation.

UDAQ should also have required modeling of all three units together to determine if the power plant will cause or contribute to PM_{10} non-attainment in Utah County.

Response:

Additional modeling submitted by IPA in July of 2003 showed that the combined impact of PM_{10}, gaseous sulfur dioxide, and gaseous nitrogen dioxide were less than the respective 24-hour and annual impact levels to require offsets, as specified in R307-403-5(1)(a). The additional analysis performed by IPA used the turbulence based dispersion option in Calpuff. This option was verbally approved by Kevin Golden before IPA performed the modeling. EPA Region VIII did not have any concerns about the use of this method as part of their comments, so the UDAQ has approved the modeling.

This rule does not require that the existing part of a facility (i.e. Units 1 and 2) be included in the model, but instead only requires that the new source or modification be included in the analysis to determine if the power plant will cause or contribute to PM_{10} non-attainment in Utah County.

Comment 16: Emission Limits during Startup, Shutdown, Malfunction, and Maintenance (pg 48, p3)

UDAQ has proposed an exemption from all BACT emission limits for periods of startup, shutdown, malfunction, and maintenance. The air quality analysis should address these types of releases and comply with all air quality standards. The assessment also must model uncontrolled emission rates from IPP Unit 3 to address malfunctions, such as if both scrubbers were to fail.

Response:

The final AO will have no automatic exemptions to the limits. Utah has reviewed the issue of startup, shutdown, malfunction, and maintenance. The "exemption" that was in the ITA has been removed and the limits will apply at all times. However, since the limits (particularly NOx) are not technically achievable during periods when the SCR is not at operating temperature, language has been added to the AO that provides the opportunity for compliance discretion during those periods of startup, shutdown, or scheduled maintenance. Malfunctions will be handled in accordance with existing state rules.

Comment 17: Class II Increment Impacts during Startup, Shutdown, Malfunction, and Maintenance (pg 49, p3)

IPSC's startup modeling analysis submitted on July 28, 2003 (attached) shows that IPP Unit 3 *would contribute to a violation of the 24-hour average PM10 Class II PSD increments*, since Unit 3's impact with other PM_{10} sources at IPP (all increment-consuming) was 37.6 $\mu g/m^3$, well in excess of the 30 $\mu g/m^3$ Class II PM_{10} increment. Pursuant to Utah regulations R307-405-6(2)(a)(i)(A) and R307-405-6(2) and (c), UDAQ cannot issue an approval order in light of these Class II increment violations unless the violations are eliminated through a more restrictive emission limit or by obtaining emission offsets.

Response:

The UDAQ does not require new or modifying sources to demonstrate compliance with the PSD Class I and II increments during periods of startup, shutdown, malfunction, and maintenance. However, when comparing IPP's original PM_{10} modeling for normal operations with the above mentioned modeling during periods of startup, shutdown, malfunction, and maintenance, it appears that approximately 8 $\mu g/m^3$ of the 37.6 $\mu g/m^3$ impact cited above, would be attributable to operations involved in bring the unit online (startup). On August 26, 2004, IPP submitted a revised PM_{10} modeling analysis that included additional control strategies for fugitive emissions. Fugitive emissions account for the greatest percentage of IPP's predicted 24-hour PM_{10} impact. Additional fugitive emission controls included surfactant to stabilize coal dust, chemical treatment of unpaved road, sweeping of all paved surfaces, and limitations on testing of emergency generators. IPA's AO will require the source to submit the proposed additional control measures for fugitive emissions as part of an enforceable fugitive dust control plan within 90 days of its issuance. The revised analysis showed that during normal operations the potential 24-hour PM_{10} impact would be 13.4 $\mu g/m^3$. Adding in the additional 8 $\mu g/m^3$ from startup operations, the potential impact would be approximately 22 $\mu g/m^3$, well below the PSD 24-hour PM_{10} Class II increment of 30 $\mu g/m^3$.

Comment 18: Non-Attainment Area Impacts during Startup, Shutdown, Malfunction, and Maintenance (pg 49, p4)

UDAQ also must require an evaluation of the startup/shutdown exemption on the Utah County PM_{10} nonattainment area. IPP Unit 3's impact on Utah County based on the "refined" modeling showed that the new Unit would cause a PM_{10} impact of almost 2 $\mu g/m^3$, and the UDAQ significance threshold is

3 $\mu g/m^3$. Thus, it seems possible that, with consideration of startup/shutdown emissions (as well as with additional years of meteorological data), IPP Unit 3 could have a significant impact on the Utah County PM_{10} non-attainment area and be required to meet lowest achievable emission rate and obtain emission offsets to minimize its impact.

Response:

Regarding the Utah County PM_{10} non-attainment area analysis, the modeling uses the combination of NO_x, SO_2, and PM_{10} with all pollutants treated equally, and modeled as being non-reactive. The total emissions release of these three pollutants over a 24-hour period is about 12% higher under startup conditions (52,247 lbs/day) than under normal operations (46,573 lbs/day). The refined CALPUFF modeling showed that roughly 2 out of the available 3 $\mu g/m^3$ 24-hour offset concentration level was impacted by Unit 3 under normal operations. Simple scaling of the normal operation impacts reveal that impacts from startups would be about 2.24 $\mu g/m^3$ in the non-attainment area and therefore will not trigger the need for offsets.

Comment 19: Class I Increment Impacts during Startup, Shutdown, Malfunction, and Maintenance (pg 50, p1)

Further, UDAQ must require the evaluation of the startup/shutdown exemptions on the Class I PSD increments and AQRVs. Without thoroughly analyzing the potential impacts that will be allowed by UDAQ's planned exemption from meeting BACT emission limits during startup, shutdown, malfunction and maintenance, UDAQ cannot adequately assess whether IPP Unit 3 will cause or contribute to adverse impacts on AQRVs or to Class I increment violations.

Response:

The UDAQ and draft EPA policy does not require an evaluation of the startup/shutdown emissions impact on the PSD Class-I increments or visibility.

Comment 20: Short-Term Emission Rates (pg 50, p3)

As early as October 2003, the National Park Service notified UDAQ that IPSC should have modeled the maximum 3-hr and 24-hr average SO_2 emission rates for all increment-consuming sources in the Class I increment analysis. The Park Service stated that when such sources were modeled at the appropriate emission rates, there are violations of the 3-hour average SO_2 increment at Capitol Reef National Park. On March 25, 2004, the National Park Service again notified UDAQ of those increment violations when the appropriate emissions were modeled (see p 5 of March 25, 2004 letter from the NPS to UDAQ, attached[1]). Pursuant to R307-405-6(2) and R307-401-6(2), UDAQ cannot issue the Approval Order for Unit 3 without requiring emission limitations or emission offsets to avoid a violation of the Class I PSD increment at Capitol Reef NP. There is no justifiable technical or legal basis for allowing IPSC to model

[1] Note that the National Park Service letter erroneously claimed that, because IPP Unit 3's impact on the SO2 increment violations was below the "significant impact level" or "SIL," IPP Unit 3 would not be considered to cause or contribute to the increment violation. However, there is no legal or regulatory basis in Utah regulations or in the federal PSD regulations to consider a source's impact on an increment violation as insignificant. Further, this is contrary to EPA's interpretation of the law. EPA Region VIII stated in an April 12, 2002 letter to the North Dakota Department of Health that the use of significant impact levels to allow a PSD permit to be issued in the case of an area showing increment violations is not consistent with the intent of the Clean Air Act's PSD program. (See attached April 12, 2002 letter).

annual average SO_2 emission rates from contributing sources in its 3-hour and 24-hour average SO_2 PSD increment analysis for the affected Class I areas.

Response:

The October 2003 and March 2004 letters the commenter references were part of communications between the two agencies as they conducted parallel reviews of the Class I and AQRV analyses. A cooperative effort between the NPS, the PSD applicant, and the State of Utah began almost a year prior to the submittal of the NOI. The UDAQ, at the Park Service's request, brought the Federal Land Manger (FLM) onboard at that time to ensure that the Class I and AQRV methodologies developed for the IPP Unit 3 analyses would adequately address the concerns of both agencies. Comments such as those submitted in the two letters are working points between the two agencies based on a preliminary review of the modeling, and do not always represent the agency's final position. The UDAQ has discussed the applicability of the emissions data used in the preliminary analysis with the NPS, and found some of the values used to be questionable. The NPS's May 27, 2004, final comment letter to the UDAQ outlining their concerns with the proposed IPP Unit 3 addition, stated that "IPP-3 would not cause or contribute to the modeled 3-hour increment violation" and "this emissions issue should not effect the IPP-3 permit." The NPS's March 25, 2004, letter also included this statement.

The Clean Air Act requires that degradation to the atmosphere be limited to the "maximum allowable increase" in concentrations levels of SO_2, PM_{10}, and NO_2 set forth in the Act, and that increment consumption for existing sources of these pollutants shall be based on "actual changes in emissions since the baseline date." The NPS analysis uses Continuous Emissions Monitoring (CEM) data that includes the substitution of artificially inflated maximum hourly emission rate for periods when the CEM was offline, in order to meet the requirements of the Acid Rain emissions credit portion of the program. The NPS analysis also did not pair actual hourly emission releases in space and time with actual hourly weather data to verify that the increment violation would likely have occurred

At the time IPA established its Class I and AQRV modeling methodology with the NPS and UDAQ, the 1996 Fifth-Generation NCAR / Penn State Mesoscale Model (MM5) data set was the acceptable meteorological data set for modeling Class I and AQRV impact in the US. The data set provides nation-wide coverage of wind flow patterns across the country for the full year, and was developed and agreed upon through a cooperative effort between the EPA, the FLM's, and State agencies. This one-year data set also met IPA's legal requirement for long-range transport modeling at the time the methodology was developed. PSD modeling guidance further requires that estimates of actual emissions for existing sources be based on the most current two-year period representing normal operations at the facility. In the case of IPP, that period was 2000 through 2001. Since the emissions data could not be paired in time and space with the meteorology, the UDAQ elected to allow the use of an emission methodology that better represented normal operations at the facilities, and would result in concentration estimates in the Class I areas that had a higher statistical probability of actually occurring. The UDAQ believes that the increment consumption methodology used in the analysis meets the requirements of the Clean Air Act, and that no further Class I increment modeling for this permit action is warranted.

Comment 21: Class I Area Analysis (pg 52, p3)

IPSC failed to model the maximum short-term emissions from all contributing sources in its Class I increment analysis. The analysis is also incomplete because IPSC did not include all increment-consuming sources, the analysis did not model three years of meteorological data, and because IPSC did not model its startup/shutdown/malfunction/planned maintenance emissions for impacts on the PSD increments. IPSC failed to include any emissions from Unit 1 at the PacifiCorp-Hunter power plant.

Response:

See response to Comment #13, 16, and 20. The UDAQ did not require that NEVCO be included in the IPP analysis at the time the modeling protocol was approved, since the NEVCO application was not complete at that time. In addition, since NEVCO impacts on all Class I areas are below the Class I SIL for all pollutants (less than 5% of the Class I increment standards), it is not expected that their contribution would result in a Class I increment violation when added to IPA and other increment consuming source impacts. This same argument applies to other ongoing energy projects, which have submitted applications since the modeling for IPP was approved by the UDAQ. Pacificorp's Hunter Power Plant - Unit 1 was permitted under the PSD regulations. However, the unit began operation in 1978 before the major baseline date of August 17, 1979. Unit 1 has not undergone any major modifications since it originally began operation. The emissions and associated impacts are considered part of the baseline concentration and do not consume increment.

Comment 22: Visibility Impacts (pg 53, p4)

IPSC did not follow FLM recommended procedures to estimate Unit 3's visibility impacts on nearby Class I areas. Instead, IPSC devised a method to essentially discount the significant changes in visibility that the new unit will cause on nearby Class I areas. The IPSC analysis should also include the use of three years of meteorological data.

Response:

As stated in their May 27, 2004, letter to the UDAQ, the Park Service found no adverse impact to visibility in any of Utah's Class I area. The use of transmissometer data was not part of the original modeling protocol approved by the NPS. The analysis performed by the NPS also showed impacts less than 5% at all parks. A maximum change of 4.26% was predicted at Capitol Reef National Park when the 1996 MM5 data was used. Also, see response to Comment #13. Furthermore, the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) 2000 Report is guidance and not a rule. Specific circumstances associated with the exact procedures necessary to carry out the recommendations in FLAG often times must be addressed on a case-by-case basis. The permitting record for this application addresses these considerations.

Comment 23: Visibility Impacts (pg 53, p4)

The FLM (Park Service) refined the visibility impacts analysis for IPP Unit 3 by modeling a second year of meteorological data from the NEVCO Sevier power plant application. Based on the second year of data modeled, the FLM found that there were multiple days with a greater than 5% change in visibility at Capitol Reef and Canyonlands, and one day at Bryce Canyon. Further, UDAQ appears to be violating R307-406-3(1), as it does not appear that UDAQ considered the FLM's 1999 meteorological data visibility analysis of IPP Unit 3.

Response:

The analysis conducted by the NPS, as stated in their May 27, 2004 comment on IPP Unit 3, ultimately led to the determination by the NPS that IPP - Unit 3, "*would not cause an adverse impact on visibility (as defined in 40 CFR 51.301)*" in any of Utah's five Class I areas. Their analysis predicted a maximum reduction in visual range of 9.75% at Capitol Reef National Park. The UDAQ concurs with this determination.

Comment 24: Visibility Impacts (pg 54, p4)

(PG 54) Under Utah's regulations, it is the Executive Secretary's responsibility to determine whether a proposed source would adversely impact visibility in any Class I area and to "insure that source emissions will be consistent with making reasonable progress toward the national visibility goal referred in 40 CFR 51.300(a)." R307-406-2.

Response:

The requirements of 40 CFR 51.300(a) regarding new source review deals only with plume blight since at the time of the rule's conception scientific tools designed to evaluate the cause and effects of regional haze were not available. The UDAQ does require major PSD sources to perform plume blight modeling using VISCREEN or PLUVUE, in order to satisfy R307-406-2. The result of IPA's plume blight analysis indicated that all levels of potential impacts were within acceptable levels.

The UDAQ has committed considerable focus and resources to protecting the air quality in its Class I areas. The UDAQ has worked with EPA and the Federal Land Managers to develop 'Utah specific' haze methodologies using the most current modeling tools and guidance. In December of 2003, the UDAQ submitted a State Implementation Plan to EPA, in order to insure that future emission levels will be consistent with making reasonable progress toward the national visibility goals. It also adopted new rules for protecting visibility at that time.

Comment 25: Cumulative Visibility Impacts (pg 55, p1)

In the National Park Service March 25, 2004 letter, it indicated that they had modeled the cumulative impacts from IPP Units 1 and 2 with the proposed new Unit 3 and found numerous days with impacts greater than a 10% change in extinction at all five of Utah's Class I areas. The National Park Service thus concluded, "Emissions from IPP-1 and 2 significantly impact visibility at Class I parks in the region."

Response:

This permit action is for Unit 3 and does not involve Units 1 and 2, as Units 1 and 2 have not been modified in the ITA under consideration. In addition, the ultimate finding of the Park Service in their May 27, 2004 letter states that there is no adverse impact (see comment #23 response).

Comment 26: Visibility Impacts (pg 55, p2)

(PG 55) According to Utah regulation R307-406-2(3), UDAQ is to ensure that "source emissions will be consistent with making reasonable progress toward the national visibility goal referred to in 40 CFR 51.300(a)."

Response:

In addition to the response given to comment #24, the UDAQ would like to add that since no adverse visibility impacts were deemed by the NPS, no mitigation was required to reduce those impacts.

Comment 27: Visibility Impacts (pg 55, p4)

(PG 55) The FLM's modeling analysis shows that the existing IPP units are significantly impairing visibility at all of the state's Class I areas, and that IPP Unit 3 will impair visibility as well. According to

the Park Service, if SCR technology were installed at IPP Units 1 and 2, NOx emissions would be reduced by almost 34,000 tons-per-year.

Response:

This permit action is for Unit 3 and does not involve Units 1 and 2, as Units 1 and 2 have not been modified in the ITA under consideration. The NPS specifically stated in the first page of its May comment letter that IPP Unit 3, "*would not cause an adverse impact on visibility (as defined in 40 CFR 51.301*

Responses to Environmental Group's June 30, 2004 comment letter on the addition of IPP - Unit 3

Comment 1: Soils and Vegetation Analyses (pg 1, p3)

The federal Clean Air Act and Utah regulations require a PSD applicant to provide a full and complete analysis of "the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification." The analysis must include those scientific studies that confirm the harmful effects that emission have on crops and native vegetation.

Response:

Adverse soil impacts in the vicinity of IPA are not expected to occur, since the maximum impacts from sulfur and nitrogen are several kilometers away, and very low compared to the secondary NAAQS. Impacts on vegetation are included in the NOI, and are adequate for purposes of fulfilling the requirement of the regulation (see section 8.15). Further, there were no comments from local farmers that indicated their crops were being impacted by IPP Units 1&2. Plume impacts from Unit 3 are less than the impacts from Units 1 & 2, therefore they are not considered adverse.

EXHIBIT C

Intermountain Power Agency

January 13, 2006

Rick Sprott
Executive Secretary
Utah Division of Air Quality
150 North 1950 West
Salt Lake City, UT 84116

Re: IPA Unit 3 Request for 24 Month Extension

Dear Mr. Sprott:

The Intermountain Power Service Company ("IPSC") submits this request for a twenty-four (24) month extension of the period within which to commence construction under Approval Order #DAQE-AN0327010-04. The AO was issued by the Utah Department of Air Quality ("UDAQ") on October 15, 2004 for the addition of a new Unit 3 at the Intermountain Power Generating Station. The request will extend the time period to commence construction from April 15, 2006 until April 15, 2008.

Construction Status

General Condition #8 of the AO indicates that IPSC shall notify you in writing on the status of construction and/or installation of Unit 3 within 18 months of the issuance of the AO. The development participants have been actively engaged in many project development activities at great expense, including the following:

- developing joint ownership arrangements
- preparing agreements to govern the use of facilities in common with units 1 and 2
- preparing a joint operating agreement covering units 1, 2 and 3
- exploring fuel supply strategies
- initiating engineering and other technical work prerequisite to the procurement of equipment.

The development participants have spent in excess of $5 million dollars in preparatory work for the Unit 3 project and will continue to vigorously pursue these ongoing activities leading to the selection of an owner's engineer, preparation of

10653 South River Front Parkway, Suite 120, South Jordan, Utah 84095
(801) 938-1333 Fax (801) 938-1330

detailed specifications for construction, and procurement of necessary equipment and on-site construction activities commencing before April 15, 2008.

Extension Requests

Extension requests for major coal plants and other complex facilities are not uncommon. The Wyoming DEQ recently granted a 24 month extension to the Two Elks project and the North Dakota Department of Health granted a 36 month extension for a North Dakota PSD permit. Other states have granted extensions as well.

AO Timing

It is, quite literally, not possible to complete all of the tasks necessary to develop, design and construct a coal-fired power plant of this size in the 18 month window prescribed in the AO. For that reason, AO General Condition #8 and the underlying requirements contemplate a process to extend the AO as necessary.

In addition to the amount of time required to complete the development tasks noted above, there are long lead times for many construction-related activities and significant timing needs associated with the financial complexities surrounding a project with construction costs of over $1 Billion-a complicated 950 MW Unit 3 project with unique features, i.e. engineering designs, financing, and ownership. In addition, the legal challenge to AO and the subsequent appeal of the Air Board's decision has taken a tremendous amount of time and resources. Until that legal challenge is completed, the AO does not have the certainty necessary to make final construction plans and finalize financing.

Discussions among the development participants likewise require large amounts of time, along with the time to complete the resource planning requirements of individual development participants (including the SB 26 mandated PSC approval process for PacifiCorp). For all of these reasons, IPSC believes that adequate justification exists to extend the 18 month timeframe to commence construction for an added 24 months. The need is even greater because one of the original development participants unexpectedly withdrew from the project—the Los Angeles Department of Water & Power (LADWP). This in and of

itself caused significant delay and is an added reason why an extension is necessary.

BACT Update

IPSC and the development participants are mindful of the need to assure that there have not been any significant changes in Best Available Control Technology ("BACT") determinations since the AO for Unit 3 originally was issued. In that regard, a study by CH2MHill has gathered BACT determinations for facilities similar to the new Unit 3 at the Intermountain Power Generating Station, issued since October 15, 2004. See Attachment A for a list of the BACT determinations updated since October 15, 2004. This study reveals that no new pollution control technologies have been determined as BACT for facilities similar to Unit 3. Based on this review, IPSC has determined that no new technologies or emissions levels have been established as BACT that would require any revisions to the AO.

Accordingly, IPSC respectfully requests that a twenty-four (24) month extension be granted to allow IPSC sufficient time to further develop, design and begin construction on the new Unit 3. Thank you for your attention to this matter, and please contact me with any questions.

Sincerely,

Reed T. Searle

Reed T. Searle
General Manager

Enclosures
Cc: Doug Hunter, UAMPS
Ernie Wessman, PacifiCorp

Attachment A

The Approval Order for IPP Unit 3 was issued on October 15, 2004. Since that issuance, some new air quality construction permits have been issued for pulverized coal fired utility boilers. Enclosed is an updated listing of these permits similar to the one that was included in the appendix of the original Notice of Intent for IPP 3.

The permits that were issued subsequent to October 15, 2004 and were reviewed are Comanche Unit 3, Weston Unit 4, WYGEN Unit 2, Newmont Unit 1, as well as the re-issuance of the Bull Mountain Roundup Units 1 and 2 permit.

CH2M HILL has reviewed these permits and has determined that for NOx, all of these permits are in the range of 0.07 to 0.08 pounds per million BTU 30 day rolling average. The IPP AO is 0.07 pounds per million BTU 30 day rolling average. Therefore there is no justification to revise the IPP NOx limit.

For SO_2, all of these permits are in the range of 0.09 to 0.10 pounds per million BTU 30 day rolling average. The IPP AO is 0.09 pounds per million BTU 30 day rolling average and 0.10 24 hour average. Therefore there is no justification to revise the IPP SO2 limit.

For CO the permits range from 0.13 to 0.15 pounds per million BTU with the Comanche permit at 0.13 pounds per million BTU eight hour rolling average during normal operation but a much higher limit of 0.30 pounds per million BTU during startup. The Newmont permit is for a shorter averaging time (24 hour rolling average) while the IPP AO CO limit is for 30 day rolling average of 0.15 pounds per million BTU. The IPP AO is well in the range of the most recent permits and therefore we see no reason to revise the IPP CO limit.

For VOC, the permits range from 0.0027 to 0.01 pounds per million BTU. The Newmont permit is for 8.1 pounds per hour which is equivalent to 0.004 pounds per million BTU at full load. The IPP AO is 0.0027 pounds per million BTU which is the lowest BACT limit. Therefore we see no reason to revise the IPP VOC limit.

For PM_{10}, the permits range from 0.012 to 0.18 pounds PM_{10} filterable per million BTU. The IPP AO is at 0.012 pounds per million BTU for a three test run average. This is the lowest BACT limit of all the permits and therefore we see no reason to revise the IPP PM_{10} limit.

For H_2SO_4, the permits range from .001 to 0.005 pounds per million BTU. The IPP AO limits H_2SO_4 emissions to .0044 pounds per million BTU 24 hour block average. The Newmont limit is 0.001 pounds per million BTU (2.04 pounds per hour) using a dry lime FGD system while IPP Unit 3 will use a wet limestone scrubber. Given this difference in sulfur control technology the Newmont permit limit for H_2SO_4 is inapplicable. The remaining permits range from 0.0042 to .005 and the IPP is in this range. Therefore we see no reason to revise the IPP H_2SO_4 limit.

TABLE E-1
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for CO
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Proper Boiler Design and Opera	not given	0.15	lb/MMBTU		12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Combustion Control	not given	0.15	lb/MMBtu		7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Combustion Control	not given	0.13	lb/MMBtu	8-hour Rolling avg.	7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Good Combustion Controls	not given	0.15	lb/MMBTU	24-hour	5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Combustion Control	not given	0.15 3,399	lb/MMBTU tons/yr	1-Day 12-month Rolling avg.	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	Combustion Control	not given	0.15 3,000	lb/MMBTU lbs/hr	30-day Rolling avg. 8-hour Block avg.	10/15/2004

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/tin/catc) was queried for the following:
- RBLC Determinations added during or after October 15, 2004
- SIC Code: 4911
- Process Type Code: 11.100 - Coal Combustion

TABLE E-2
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for VOC
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Proper Boiler Design and Operation	not given	0.003	lb/MMBtu		12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Combustion Control	not given	0.01	lb/MMBtu		7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Combustion Control	not given	0.0036	lb/MMBtu		7/5/2005
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Combustion Control	not given	0.0036 81.6	lb/MMBTU tons/yr	1-Day 12-month Rolling avg.	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr		not given	0.0027	lb/MMBTU	3 stack test run average	10/15/2004

Notes:

TABLE E-3
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for PM
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Fabric Filter	not given	0.012	lb/MMBTU	24-hour	5/05/2005 No. AP4911-1349

Notes:

TABLE E-4
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for PM_{10}
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Fabric Filter Baghouse	not given	0.012	lb/MMBTU		12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Fabric Filter	not given	0.012	lb/MMBtu		7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Fabric Filter	not given	0.012 0.020	lb/MMBtu	3-hour Rolling avg (filterable) 3-hour Rolling avg (filterable & condensable)	7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Fabric Filter	not given	0.012	lb/MMBTU	24-hour	5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Fabric Filter	not given	0.018	lb/MMBTU	3-hour Rolling avg.	10/18/2004
	Intermountain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	Fabric Filer	not given	0.012 221	lb/MMBTU lbs/hr	3 stack test run avg. 24-hour Block avg	10/15/2004

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:

TABLE E-5
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for Lead
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit	Averaging Period	Permit Date and Permit No.

Notes:

TABLE E-6
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for Fluorides
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit	Averaging Period	Permit Date and Permit No.
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant	1	Coal Fired Boiler 2030 MMBTU/HR	Dry Spray Scrubber and Fabric Filter	not given	1.17 lbs/hr		5/05/2005 No. AP4911-1349

Notes:

TABLE E-7
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for SO_2
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Dry Flue Gas Desulfurization System	90%	0.15	lb/MMBtu	1-hour	12/06/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Dry Lime FGD	not given	0.10 0.12	lb/MMBTU lb/MMBTU	30-day Rolling avg. 3-hour Block avg.	7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Dry Lime FGD	not given	0.1	lb/MMBtu	30-day Rolling	7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Lime Spray Dryer Scrubber	not given	0.09 0.065	lb/MMBTU lb/MMBTU	24-hour (Coal S >= 0.45%) - 95% removal eff, 30-day period 24-hour (Coal S <0.45%) - 91% removal eff, 30-day period	5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Dry Lime FGD	not given	0.10 0.09	lb/MMBTU lb/MMBTU	24-hour Block avg. 30-day Rolling avg.	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	Wet Limstone FGD	not given	0.10 0.09	lb/MMBTU lb/MMBTU	24-hour Block avg. 30-day Rolling avg.	10/15/2004

Notes:

TABLE E-8
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for NO_x
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	SCR, Low NOx Burners, and Overfire Air	not given	0.1	lb/MBtu	1-hour	12/08/2005 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	SCR and Low NOx Burners	not given	0.07	lb/MBtu	30-day Rolling	7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	SCR and Low NOx Burners	not given	0.08	lb/MBtu	30-day Rolling	7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	SCR, Low NOx Burners, and Overfire Air	not given	0.067	lb/MBtu	24-hour rolling	5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	SCR and Low NOx Burners	not given	0.07	lb/MBtu	30-day Rolling	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	SCR and Low NOx Burners	not given	0.07	lb/MBtu	24-hour	10/15/2004

Notes:

TABLE E-9
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for H_2SO_4
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Dry Flue Gas Desulfurization System	not given	0.0064	lb/MMBTU		12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Dry Lime FGD	not given	No Limit			7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Dry Lime FGD	not given	0.0042	lb/MMBtu		7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Dry Spray Scrubber and Fabric Filter	not given	2.06	lbs/hr		5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Dry Lime FGD	not given	0.005	lb/MMBTU	24-hour	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	Wet Limestone FGD	not given	0.0044	lb/MMBTU	24-hour Block avg	10/15/2004

Notes:

TABLE E-10
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for Beryllium
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit	Averaging Period	Permit Date and Permit No.

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:
- RBLC Determinations added during or after January 1995
- SIC Code: 4911
- Process Type Code: 11.110 - Coal Combustion

The State
of Wyoming

Dave Freudenthal, Governor

Department of Environmental Quality

Herschler Building • 122 West 25th Street • Cheyenne, Wyoming 82002

ADMIN/OUTREACH	ABANDONED MINES	AIR QUALITY	INDUSTRIAL SITING	LAND QUALITY	SOLID & HAZ. WASTE	WATER QUALITY
(307) 777-7758	(307) 777-6145	(307) 777-7391	(307) 777-7368	(307) 777-7756	(307) 777-7752	(307) 777-7781
FAX 777-3610	FAX 777-6462	FAX 777-5616	FAX 777-6937	FAX 777-5864	FAX 777-5973	FAX 777-5973

May 17, 2004

Mr. Fred Carl
Director Environmental Services
Black Hills Corporation
P.O. Box 1400
Rapid City, SD 57709

Re: Air Quality Permit CT-3030 Extension

Dear Mr. Carl:

The Division is in receipt of your letter dated March 25, 2004, requesting to extend the construction period for Air Quality Permit CT-3030. Permit CT-3030, issued September 25, 2002, authorized the construction of a 500 megawatt (MW) pulverized coal fired electric generating facility, known as WYGEN 2, located at 13151 Hwy 51 approximately five (5) miles east of Gillette in Campbell County, Wyoming.

Condition 6 of the issued permit states that construction shall commence within 24 months of issuance of the permit. The allotted 24 months for construction is scheduled to lapse on September 25, 2004. An appeal of the final permit was filed on November 25, 2002 and action on the appeal is pending. For this reason, the Division will extend the permit for a period of one year. Construction must commence prior to September 25, 2005, for the approval to construct the WYGEN 2 Electric Generating Plant to remain valid.

If you should have any questions concerning this matter, please contact this office at (307) 777-7391.

Sincerely,

Dan Olson
Administrator
Air Quality Division

cc: Bob Gill
Mike Warren
Main File CT-3030

EXHIBIT D

State of Utah

Department of
Environmental Quality

Dianne R. Nielson, Ph.D.
Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

FILE COPY

DAQE-GN0327010-06

January 27, 2006

Reed Searle
Intermountain Power Agency
10653 South River Front Parkway, Suite 120
South Jordan, Utah 84095

Re: Review of the Approval Order DAQE-AN0327010-04 dated October 15, 2004.

Dear Mr. Searle:

The Utah Division of Air Quality (UDAQ) has received your letter dated January 13, 2006 in accordance with Approval Order number DAQE-AN0327010-04.

UDAQ reviewed your AO in accordance with the R307-401-11 of the Utah Administrative Code (UAC) and prepared the attached Memo.

Please note that Executive Secretary will not exercise the right to revoke the above referenced AO as outlined in R307-401-11. However, by April 15, of 2008, IPSC shall again notify the Executive Secretary in writing on the status of the construction and/or installation. At that time the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11, UAC.

Sincerely,

Richard W. Sprott, Executive Secretary
Utah Air Quality Board

RWS: MR:kw
Attachment: GN0327010A-06

State of Utah

Department of Environmental Quality

Dianne R. Nielson, Ph.D.
Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

FILE COPY

DAQE-GN0327010A-06

MEMORANDUM

TO: Intermountain Power Service Corporation (IPSC) Project Source File (Site ID 10327)

THROUGH: Richard W. Sprott, Executive Secretary RWS 1/24/06
Regg Olsen, Permitting Branch Manager
Rusty Ruby, NSR Section Manager, R 1/24/06

FROM: Milka Radulovic, NSR Engineer

SUBJECT: Review of the Approval Order (AO) for IPSC Unit #3 number DAQE-AN0327010-04 in Accordance with Condition 8 and Utah Administrative Code (UAC) Rule 307-401-11

DATE: January 23, 2006

We reviewed the IPSC letter dated January 13, 2006, sent to UDAQ in accordance with AO Condition 8. Reviewing the letter UDAQ finds that IPSC is engaged in many project development activities at substantial expense in excess of 5 million dollars.

UDAQ also finds that on November 12, 2004, IPSC petitioned the Utah Air Quality Board for review of Condition 24 in the AO dated October 15, 2004. Settlement negotiations took place between UDAQ and IPSC, resulting in a Joint Stipulation. The Joint Stipulation was approved by the Order of the Air Quality Board on September 7, 2005. The AO incorporates the terms of the Joint Stipulation. In addition, on November 15, 2004, Western Resources Advocates appealed the AO and action on the appeal is pending. These actions caused significant delay and necessitated an extension of the construction program.

For these reasons the Executive Secretary will not exercise the right to revoke the above referenced AO as outlined in R307-401-11. However, by April 15, of 2008, IPSC shall again notify the Executive Secretary in writing on the status of the construction and/or installation. At that time the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11, UAC.

EXHIBIT E

UAMPS
UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS
2825 E. Cottonwood Parkway
Suite 200
Salt Lake City, Utah 84121-7077
Phone: 801-566-3938
Toll Free: 800-872-5961
Fax: 801-561-2687

N0327-016

UTAH DEPARTMENT OF
ENVIRONMENTAL QUALITY
AUG - 7 2006
DIVISION OF AIR QUALITY

August 4, 2006

Mr. Rick Sprott
Utah Division of Air Quality
150 North 1950 West
Salt Lake City, Utah 84114

Re: Engineering and Procurement of IPSC Unit 3 Boiler-Supercritical

Dear Mr. Sprott:

We are writing concerning our intent to use a supercritical boiler design for the Intermountain Power Service Corporation (IPSC) Unit # 3 to be located near Delta, Utah. The IPSC Unit 3 Development Committee is preparing bids for the engineering and procurement phase of construction. This letter is part of our efforts to keep the Division apprised of our construction status. As you recall, in December 2002, IPSC submitted a Notice of Intent (NOI) to permit and construct this nominal 950-gross megawatt (MW) (900-net MW) pulverized coal (PC) fired unit. An Approval Order (AO) for the construction of the proposed project was issued by the Utah Division of Air Quality (UDAQ) on October 15, 2004. The AO does not specify the specific type of PC-boiler the facility must use.

As we have proceeded with the highly complex process of developing the plant, we have concluded that a supercritical boiler design is more efficient and better for the environment, that it reflects the latest engineering and market developments for PC facilities, and that it accommodates those who favored a supercritical boiler design in their comments regarding the AO. We believe that use of a supercritical boiler design is consistent with the AO. We are preparing to order this equipment, and want to notify you prior to entering into an Engineering, Procurement and Construction (EPC) contract. We do not believe that any update of the AO is necessary in response to this notification letter. The following information is submitted to explain our conclusion that a supercritical design is consistent with the AO.

What is the difference between a Subcritical and Supercritical Boiler Design?

A supercritical boiler is functionally equivalent to a subcritical boiler except that, in order to create greater efficiencies, a supercritical boiler generates steam at higher pressures and

temperatures. This makes supercritical boiler-turbine technology more efficient in converting heat from the burning coal to driving the steam turbine generator. In all other respects, a supercritical boiler is equivalent to a subcritical design.

In a typical fossil-fuel boiler, water-containing tubes line the inside of the furnace walls. Fuel is ignited and burned as it enters the furnace. The burning fuel releases thermal energy, which is absorbed by the water in the tubes. As the temperature of the water rises, the water begins to boil. Water and steam are separated in a boiler drum and the steam, after additional heating in the boiler, is piped from the boiler to the steam turbine.

In a supercritical boiler design, the operating pressure exceeds the critical point of water. The critical point of water is at a pressure of 3,208 pounds per square inch absolute (psia); a point above which distinct liquid and vapor (steam) phases no longer exist, and the water is in a supercritical fluid state. Water and steam separation occurs without a boiler drum and the superheated fluid is sent directly to the steam turbine. A plant operating at this high pressure is more energy efficient and is referred to as a supercritical unit. Other than the higher operating pressure and temperature of steam at the supercritical plant, the design features are equivalent to a subcritical unit.

The subcritical boiler design has a 2520 psig/1050°F/1050°F steam power cycle providing a net plant efficiency (HHV)1 of approximately 35.77 percent, while the supercritical boiler design typically has a 3500 psig/1050°F/1100°F steam power cycle providing a net plant efficiency (HHV) of approximately 36.75 percent. As a result, there is approximately a three percent improvement in heat rate between the two cycles, thereby increasing the power output of the steam turbine-generator for the same coal burned in the boiler. Alternatively, a supercritical boiler can produce the same level of power output using a lesser amount of coal.

Using a supercritical boiler will not increase the heat input rate or the emission limits included in the AO. It will not increase coal consumption limits or alter the fuel types. The supercritical boiler will have the same maximum gross heat input of 9,050 million British Thermal Units per hour (MMbtu/hr), as listed in the AO. No changes will occur to the stack parameters. The stack will be designed with the same exit velocity and temperature as modeled. Therefore no additional dispersion modeling should be required since the emissions are the same and the stack parameters will not change.

---

[1] Net Plant Efficiency (HHV) is defined as the net electrical output of the plant divided by the higher heating value fuel consumption of the plant.

Will emissions remain stable or decrease with a supercritical boiler design?

Unit emissions, coal feed rate and heat input to the boiler will in all cases remain at or below the levels specified in the AO. See Exhibit 1 for a comparison of the sub critical design and supercritical boiler design.

Installation of a supercritical boiler will result in a net decrease in emissions as measured in lbs/MWh. Also, as with the subcritical boiler design, the supercritical boiler will use a baghouse for particulate emissions control, a wet limestone scrubber for control of sulfur dioxide and acid gas emissions; and Low NOx Burners/Over-Fire-Air and Selective Catalytic Reduction for NOx emissions control. The design of the emissions control equipment will be the same as for the subcritical design.

Are BACT-Level Emission Controls the same for Supercritical and Subcritical Boilers?

The BACT analysis completed for IPP3 showed that BACT-Level emission controls were the same for both designs. The same list of potential control technologies were considered for each pollutant in the BACT analyses for supercritical units as was used in the IPSC Unit 3 PC BACT analysis. The control effectiveness of the technologies for each pollutant was also the same. No distinction was made between the supercritical PC boiler design of these units and the subcritical PC design of other units when consulting the EPA's RACT/BACT/LAER Clearinghouse (RBLC) and recently approved PSD permits to assist in selecting BACT for the projects. The primary difference between the BACT analysis outcomes for the various units was that a wet limestone FGD process was selected for IPSC Unit 3 with an emission limit of 0.09 Lb/MMBtu on a 30 day rolling average based on burning western bituminous coal versus some of the other units which each selected a dry lime FGD process with an emission limit of 0.10 Lb/MMBtu based on burning subbituminous Powder River Basin (PRB) coal. Low-NOx burners with Selective Catalytic Reduction were selected as BACT for NOx control and fabric filters were selected as BACT for Particulate Matter (PM) control.

The BACT process evaluates pollution control equipment in order to determine a proper BACT emission rate; it does not evaluate the boiler design. UDEQ (and EPA) have repeatedly confirmed this. Whether the boiler is subcritical or supercritical design, the BACT process evaluates the same pollution control equipment. The results of the IPP3 BACT analysis showed that there is no difference in pollution control equipment or BACT emission limits between a subcritical and a supercritical boiler.

Is it necessary to update the existing AO?

We believe it is not necessary to update the AO. When UDAQ issued its AO, DAQE-AN0327010-04, for the new IPSC Unit 3 on October 15, 2004, the AO approved installation of a "Dry-bottom Pulverized Coal Fired Boiler for base load operation with Overfire Air Ports

System" or its equivalent (the NOI described the unit as "an indoor type, subcritical, PC-fired boiler designed for base load operation" and then the AO imposed permit conditions to limit emissions). See AO at Condition #7. The AO does not specify the type of boiler as subcritical or supercritical. The AO only species the maximum heat input rate, 9050 x 106 Btu/hr, and the coal consumption limits, 3,541,248 tons of coal burned per rolling 12-month period. See AO Condition #7 and Condition #14. In addition, the AO limits the fuel to either "bituminous or blend of bituminous and up to thirty percent subbituminous coals." See AO at Condition #19. Selection of a supercritical boiler will not affect or exceed the heat input rate, the consumption limits or the types of fuel specified in the AO. Selection of a supercritical boiler does not constitute a major modification because it does not constitute a physical change or change in operation of an existing source and does not result in a significant emissions increase. Indeed, as noted, the emission limits will be the same for a subcritical or supercritical design. Selection of a supercritical boiler will not affect or exceed the heat input rate, the consumption limits or the types of fuel specified in the AO. In fact, the supercritical boiler will have the same coal consumption rate and the same gross heat input rate allowed in the AO, but it will be more efficient. Accordingly, a supercritical boiler design is consistent with the AO, and was the preferred boiler design of some commentrs during the public comment process for the AO. Therefore, the use of a supercritical boiler is consistent with the AO. This letter is notification to you of our continuing construction efforts, and in the near future the IPSC Unit 3 Development Committee intends to enter into an EPC contract for a supercritical boiler.

If you have any questions or need additional information, please contact me at your earliest convenience. Thank you for your consideration of this matter.

Sincerely,

Douglas O. Hunter
Chairman, Unit 3 Development Committee

Enclosure

Exhibit 1
IPP Unit 3 Project
Unit 3 Boiler Emissions Comparison

	Permit Basis Subcritical Design	Super Critical Boiler Design
Coal Feed Rate (tons/hr)	404	404
Heat Input to Boiler (MMBtu/hr)	9,050	9,050
Annual Capacity Factor (%/yr)	100	100
NOx		
NOx Boiler Emissions (lb/MMBtu)	0.35	0.35
NOx Stack Emissions (lb/MMBtu)	0.070	0.070
SO_2		
SO_2 Boiler Emissions (lb/MMBtu)	1.34	1.34
SO_2 Stack Emissions (lb/MMBtu)	0.090	0.090
CO		
CO Emission Factor (lb/MMBtu)	0.154	0.154
Filterable PM		
Filterable PM Stack Emissions (lb/MMBtu)	0.013	0.013
Filterable PM_{10}		
Filterable PM_{10} Stack Emissions (lb/MMBtu)	0.012	0.012
VOC		
VOC Emissions (lb/MMBtu)	0.00268	0.00268
Sulfuric Acid Mist		
H_2SO_4 Stack Emissions (lb/MMBtu)	0.00439	0.00439
Ammonium Sulfate		
$(NH_4)_2SO_4$ Stack Emissions (lb/MMBtu)	0.00030	0.00030
Hydrogen Chloride		
HCl Stack Emissions (lb/MMBtu)	0.00421	0.00421
HCl Stack Emissions (lb/hr)	38.13000	38.13000
Hydrogen Fluoride		
HF Stack Emissions (lb/MMBtu)	0.001	0.001
Stack Conditions		
Stack Exit Flow (acfm)	3,244,126	3,244,126
Stack Exit Diameter (feet)	31.85	31.85
Stack Exit Temperature (degF)	135	135

EXHIBIT F

State of Utah

Department of
Environmental Quality

Dianne R. Nielson, Ph.D.
Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

DAQE-GN0327016-06

August 17, 2006

Project fee ID:N0327-016

Doug Hunter
Chairman, Unit 3 Development Committee
2825 E. Cottonwood Parkway
Salt Lake City, Utah 84121-7077

Dear Mr. Hunter

Re: Equivalency Determination for the Intermountain Power Service Corporation (IPSC) Unit 3 Pulverized Coal (PC) Fired Boiler

This letter is in response to the letter submitted August 7, 2006, concerning the installation of the IPSC Unit 3 PC boiler at the Intermountain Power Plant, near Delta, Utah . Utah Division of Air Quality agrees, that in accordance with Condition 7 of the Approval Order number DAQE-AN0327010-04*, a supercritical PC boiler is equivalent to the permitted unit.

The supercritical boiler shall operate under the conditions listed in Approval Order number DAQE-AN0327010-04*.

Please direct any technical questions you may have on this letter to Ms. Milka Radulovic. She may be reached at (801) 536-4232.

Sincerely,

Richard W. Sprott, Executive Secretary
Utah Air Quality Board

RWS:MR:kw

150 North 1950 West • PO Box 144820 • Salt Lake City, UT 84114-4820 • phone (801) 536-4000 • fax (801) 536-4099
T.D.D. (801) 536-4414 • *www.deq.utah.gov*

EXHIBIT G

HOLME ROBERTS & OWEN LLP
Blaine Rawson #7289
299 South Main Street, Suite 1800
Salt Lake City, Utah 84111-2263
Telephone: (801) 521-5800
Facsimile: (801) 521-9639

Attorneys for Intermountain Power Service Corporation

BEFORE THE UTAH AIR QUALITY BOARD

In the Matter of: Unit 3, Intermountain Power Service Corporation, Millard County, Utah DAQE-AN0327010-04	**AFFIDAVIT OF THOMAS R. GHESQUIERE**

STATE OF MICHIGAN)
: ss.
County of Washtenaw)

I, THOMAS R. GHESQUIERE, being first duly sworn, depose and state as follows:

1. I am over the age of 21 years, and I am competent to make this Affidavit. I make this Affidavit on the basis of facts known personally to me.

2. I received a Bachelor of Science degree in mechanical engineering from Michigan State University in 1984. I am licensed as a professional engineer in Michigan and Kansas. Since graduating from Michigan State, I have been working in the power industry on projects in the United States and abroad. A brief description of my professional background, together with representative projects, is attached at Tab 1. My responsibilities have included project management, project development, design engineering, and construction management. In

working on project development, I have conducted multiple analyses of pulverized coal combustion technologies, including comparisons of sub- and super-critical technologies.

3. I am currently employed by Cummins & Barnard, Inc., as a Senior Project and New Business Development Manager. As part of my employment, I am working as the Project Manager of Development Services for the Intermountain Power Project, Unit 3. As part of that role, I analyzed the viability of sub and super-critical technologies for use on the project, and it was ultimately decided to use super-critical technology.

4. Sub-critical and super-critical technologies are both pulverized coal combustion technologies. A super-critical boiler is functionally equivalent to a sub-critical boiler, except that, to create greater efficiencies, a super-critical boiler generates steam at higher pressures and typically higher temperatures. The combustion equipment, combustion process, and burners are identical.

5. The thermodynamic steam cycles for existing large pulverized coal-fire units worldwide are of two types – sub-critical and super-critical:

- Sub-critical drum type units with maximum continuous throttle pressures up to 2400 psig and typically 1000° F/1000° F superheat/reheat temperature conditions. Overpressure (OP) design conditions for this cycle would typically allow for temporary operation at a throttle pressure of 2520 psig.
    - The sub-critical unit proposed by Intermountain Power Services Corporation in this matter was more efficient than the typical sub-critical unit, with steam conditions of 2,535 psig and 1,050° F/1,050° F single reheat.
- Super-critical units with throttle pressures at 3,500 psig (3675 psig-OP) and above with 1,000° F to 1,100° F superheat and reheat temperatures. Super-critical technologies operate on a once through steam/water cycle concept with no steam drum in the steam generator flow path. Water is circulated through the boiler heat

transfer surfaces, evaporated within the boiler tubes, superheated and/or reheated, and forwarded to the steam turbine generator. Steam separation is accomplished in a vertical steam/water separations device. Super-critical cycles have typically been implemented with a single steam reheat system.

- The super-critical unit proposed by Intermountain Power Services Corporation in this matter has steam conditions of 3,677 psig and 1,050° F/1,100° F reheat.

6. Both the proposed IPP Unit 3 sub- and super-critical units have a maximum heat input to the boiler of 9,050 mmBtu/hr. Since the maximum heat input to the boiler is the same for sub and super-critical cycles, the emissions on a lb/mmBtu basis are identical when comparing the two cycles.

7. Emissions controls for the proposed IPP Unit 3sub-critical and super-critical boilers are also the same: Each use low-NOx burner design and Selective Catalytic Reduction, or SCR, for NOx control; each use a bag-house for particulate removal; each use wet flue gas desulfurization, or WFGD, for SO_2 removal. The effectiveness of these technologies for each regulated pollutant is also the same.

8. As stated in paragraph 5 above, the sub-critical boiler proposed by IPSC was more efficient than the typical sub-critical boiler. As a result, comparing the sub-critical unit IPSC actually proposed to the super-critical unit IPSC actually proposed, the proposed super-critical unit is approximately three percent more efficient.

9. However, the actual maximum net unit output and efficiency cannot be determined until the unit is installed, goes through a typical shakedown, and finally goes on line.

Thomas R. Ghesquiere
THOMAS R. GHESQUIERE

SUBSCRIBED AND SWORN to before me this 19 day of March, 2007.

Jonathan McClain
NOTARY PUBLIC
Residing at: 235 Sheldon Rd
Plymouth, MI 48170

March 7, 2012

My Commission Expires:

JONATHAN McCLAIN
Notary Public, State of Michigan
County of Wayne
My Commission Expires Mar. 7, 2012
Acting in the County of Wayne

#221478 v2

1

THOMAS R. GHESQUIERE, P.E.
Senior Project Manager/New Business Development

Over twenty-three years of professional experience in power plant development, engineering and construction. Extensive background with all types of plants; including pulverized coal, oil and gas-fired simple cycle and combined cycle units. Projects include international plants, greenfield projects, upgrades and expansions to existing plants. Has worked in various roles including Owner's Engineer, design engineer, construction manager and OEM representative. Joined Cummins & Barnard as a Senior Project and New Business Development Manager.

REPRESENTATIVE PROJECTS

Intermountain Power Agency – Project Manager of development services for the Intermountain Power Project, Unit 3. Project involves addition of a new 900 MW pulverized coal unit in Delta, Utah. Scope of services includes performing as Owner's Engineer, developing design and scope parameters, defining interfaces with the existing units at the site, developing and executing the plant procurement process, and providing project management and engineering services.

Sadaf – Lead Project Development Engineer responsible for Sadaf Cogeneration project, a 240 MW, 510 TPH cogeneration plant in Jubail, Saudi Arabia. Scope included overall technical development, and technical and commercial negotiations with the EPC contractor and the power and steam offtaker.

CMS Energy – Project Engineering Manager for the Margarita Island Power Plant. Scope included development phase services, EPC contract development and negotiation, and execution of engineering, construction and start-up of two Frame 6B combustion turbines.

Volta River Authority – Project Engineering Manager responsible for the Takoradi 2 project including EPC contract negotiations and administration of the contract to design and construct a 220 MW simple cycle plant in Takoradi, Ghana.

Chrysler Corporation – Engineering Manager responsible for coordination of data gathering, analysis, and technical writing of a life extension study that examined process steam and compressed air generation and distribution systems at the Trenton Engine Plant in Trenton, Michigan.

Pluspetrol Energy – Project Engineer responsible for coordination of studies, mechanical design, procurement and drawing production activities for the 480 MW combined cycle conversion of the Tucuman Plant in Argentina.

Sidurgica de Guatemala – Project Engineer responsible for mechanical design, procurement and drawing production activities for the EPC installation of ten diesel electric generators in Guatemala. This 40 MW project provides electric power to local utility grid and adjacent steel mill.

Consumers Energy Company – Engineering Manager responsible for conceptual design, preparation and bid evaluation of the dry fly ash handling equipment procurement specification and conversion project at the J.H. Campbell Plant.

Central Illinois Light Company – Project Mechanical Engineer responsible for mechanical design, procurement and drawing production activities for the Midwest Grain Steam/Electric Plant, a 21 MW gas–fired cogeneration unit.

EXPERIENCE HIGHLIGHTS

Project Management
Project Development
Design Project Engineering
EPC Project Engineering
Fossil Fuel Plant Design
Cogeneration Projects
Combustion Turbines
Resident Engineering Services

MAJOR CLIENTS

Intermountain Power Agency
CMS Energy
Consumers Energy
Sadaf
Volta River Authority
Pluspetrol
Central Illinois Light Company
City Public Service of San Antonio
Orlando Utility Commission

EDUCATION

BSME - Michigan State University

REGISTRATIONS

Professional Engineer: Michigan, Kansas

PROFESSIONAL ACTIVITIES

Engineering Society of Detroit

THOMAS R. GHESQUIERE, P.E.
Senior Project Manager/New Business Development

City Public Service of San Antonio – Lead Resident Field Engineer for J.K. Spruce Unit 1, a 500 MW pulverized coal-fired unit. Duties included supervising coal yard construction and inspecting main cycle systems.

ACE Cogeneration Company – Served as a Mechanical Design Engineer and performed system design, piping and instrument diagram development, and mechanical equipment specification preparation for the Argus Cogeneration Project, a 110 MW fluidized bed coal-fired unit.

Orlando Utility Commission – Resident Field Engineer, worked in the construction management group at the jobsite of the Stanton Energy Center Unit 1, a 425 MW pulverized coal unit. Administered the mechanical construction contract and the piping and equipment insulation contract.

EXHIBIT H

LEXSEE 2003 UT APP 216

Kerry Pipkin, Plaintiff and Appellant, v. Randy Haugen; Kip Cashmore; Quick Cash, LLC; USA Cash Stores; USA Cash Services; QC Instant Cash; RKT Holding Company; and Does 1-10, inclusive, Defendants and Appellees.

Case No. 20011028-CA

COURT OF APPEALS OF UTAH

2003 UT App 216; 2003 Utah App. LEXIS 283

June 26, 2003, Filed

NOTICE: [*1] NOT FOR OFFICIAL PUBLICATION

PRIOR HISTORY: Second District, Ogden Department. The Honorable Roger S. Dutson

DISPOSITION: Affirmed.

COUNSEL: Denver C. Snuffer Jr., Sandy, and Etan E. Rosen, Sacramento, California, for Appellant

Thomas R. Karrenberg and James H. Tily, Salt Lake City, for Appellees

JUDGES: Pamela T. Greenwood, Judge. WE CONCUR: Russell W. Bench, Judge, James Z. Davis, Judge

OPINION BY: Pamela T. Greenwood

OPINION:

MEMORANDUM DECISION

Before Judges Bench, Davis, and Greenwood.

GREENWOOD, Judge:

A party opposing summary judgment "'must set forth specific facts showing that there is a genuine issue for trial.'" *Peterson v. Coca-Cola USA, 2002 UT 42, P20, 48 P.3d 941* (quoting *Thornock v. Cook, 604 P.2d 934, 936 (Utah 1979)*). Plaintiff Kerry Pipkin, has failed to present "specific facts" supporting his allegations that Defendants Randy Haugen and Kip Cashmore made false statements for the purpose of establishing fraud or negligent misrepresentation. In response to Defendants' Motion for Summary Judgment, Pipkin provided only his own affidavit and his counsel's "declaration," which offer nothing more than "unsupported allegations." Id. (upholding trial court's grant of [*2] summary judgment where opposing party "offered nothing more than unsupported allegations").

Attempting to provide facts to support his allegations of Defendants' misstatements, Pipkin's affidavit alleges that he "received information" that Haughen and Cashmore had signed signature cards to continue the Quick Cash business, "learned" that Haughen and Cashmore were partners, and obtained documents establishing co-ownership. However, other than his self-serving affidavit, Pipkin produces no affidavits, depositions, documents, or interrogatories supporting his allegations. See Utah R. Civ. P. 56(c) (outlining documents admissible in opposing summary judgment motion). "Although upon summary judgment the court must view all facts and inferences in favor of the nonmoving party, it may not assume facts for which no evidence is offered." *Coca-Cola, 2002 UT 42 at P20.* Summary judgment was not improper because Pipkin's affidavit, standing alone, does not provide facts that are supported by admissible evidence.

The "declaration" of Pipkin's counsel similarly does not establish a material fact for the purpose of summary judgment because it is not in the form required [*3] by rule 56(c) of the Utah Rules of Civil Procedure. Rule 56(c) states that summary judgment may be granted if "the pleadings, depositions, answers to interrogatories, and admissions on file, together with the affidavits, if any, show that there is no genuine issue as to any material fact." Id. Here, Pipkin's counsel's "declaration" is not in the form of an affidavit. Additionally, the "facts" he argues are established by his declaration are not based on his personal knowledge. See Utah R. Civ. P. 56(e) (stating "opposing affidavits shall be made on personal knowledge"). Rather, the declaration is a summary of documents counsel obtained and inferences by counsel

regarding proof of Haugen's business relationship with Quick Cash.

Not only is the declaration inadmissible because it is not in the form required by rules 56(c) and 56(e), the attached documents are also inadmissible because they are hearsay. See Utah R. Civ. P. 56(e) (stating "opposing affidavits . . . shall set forth such facts as would be admissible in evidence"). The first document appears to be a copy of a minute entry from a California court in which a different plaintiff sued U.S.A. Cash Stores, Inc. **[*4]** The document does nothing to support Pipkin's assertion that Haugen maintained a partnership with Cashmore, nor is it a finding of fact by the California court or a disposition of the case. Additionally, the documents submitted with the declaration were not authenticated, as required by rule 901(a) of the Utah Rules of Evidence. Thus, they are inadmissible and cannot be used to establish facts for the purpose of summary judgment. See Utah R. Civ. P. 56(e).

Because Pipkin failed to set forth facts establishing a genuine issue as to any misstatement by either Haugen or Cashmore, he cannot succeed in his opposition to summary judgment. Moreover, Pipkin also failed to provide evidence that creates an issue of material fact as to injury. See *Robinson v. Tripco Inv., Inc., 2000 UT App 200, P12, 21 P.3d 219* (stating the elements of fraud include "injury and damage"). Pipkin is an experienced businessman who received $ 375,000 for the sale of a company in which he had been actively involved for several years, and did so with the assistance of counsel. Even if we determined that Pipkin's allegations of fraud or misrepresentation survive the motion for summary judgment, **[*5]** he failed to provide evidence establishing that reliance on those allegations caused him injury. n1 Establishing injury is a necessary element of fraud and negligent misrepresentation; therefore, because Pipkin failed to establish a question of fact as to his injury, summary judgment was appropriate.

n1 Pipkin alleges that Quick Cash may have been worth 1 to 1.2 million dollars at the time he sold the company to Cashmore. However, there is nothing in the record establishing Quick Cash's value at the time of the sale. Therefore, there was no evidence before the trial court establishing that Pipkin was injured when he sold his share of Quick Cash for $ 375,000.

Lastly, Pipkin's brief appears to include an appeal of the trial court's grant of summary judgment as to his claim of intentional interference with economic relations. However, while outlining evidence he believes establishes that Haugen and Cashmore were deceitful in the sale of Quick Cash, Pipkin does nothing to establish the facts necessary to **[*6]** prove intentional interference with economic relations. n2 "[A] reviewing court is entitled to have the issues clearly defined with pertinent authority cited and is not simply a depository in which the appealing party may dump the burden of argument and research." *State v. Vargas, 2001 UT 5, P42, 20 P.3d 271* (alteration in original) (quotations and citations omitted). Rule 24(a)(9) of the Utah Rules of Appellate Procedure requires Pipkin to include the "contentions and reasons" he is appealing the issue. Id. Aside from his statement that he pleaded with great specificity the claim of intentional interference with economic relations, Pipkin does nothing to show how either Cashmore or Haugen intentionally interfered with his business relations and did so with an improper purpose. See *Leigh Furniture & Carpet Co. v. Isom, 657 P.2d 293, 304 (Utah 1982)*. Because Pipkin failed to provide facts and arguments relating to intentional interference with economic relations, we refuse to address the issue.

n2 To establish intentional interference of economic relations, Pipkin must prove "(1) that the defendant intentionally interfered with the plaintiff's existing or potential economic relations, (2) for an improper purpose or by improper means, (3) causing injury to the plaintiff." *Leigh Furniture & Carpet Co. v. Isom, 657 P.2d 293, 304 (Utah 1982)*.

[*7]

Affirmed.

Pamela T. Greenwood, Judge

WE CONCUR:

Russell W. Bench, Judge

James Z. Davis, Judge

PAUL M. McCONKIE (USB# 5881)
CHRISTIAN C. STEPHENS (USB #9068)
Assistant Attorneys General
MARK L. SHURTLEFF (USB #4666)
UTAH ATTORNEY GENERAL
160 East 300 South
P.O. Box 140873
Salt Lake City, UT 84114-0873
Telephone: (801) 366-0290
Facsimile: (801) 366-0292
Attorneys for the Executive Secretary of the Utah Air Quality Board

BEFORE THE UTAH AIR QUALITY BOARD

In the Matter of: Sevier Power Company Power Plant Sevier County, Utah DAQE-AN2529001-04	EXECUTIVE SECRETARY'S MEMORANDUM IN OPPOSITION TO SIERRA CLUB'S MOTION FOR SUMMARY JUDGMENT

Pursuant to Rule 7(c)(1) of the Utah Rules of Civil Procedure, the Executive Secretary of the Utah Air Quality Board ("Executive Secretary") submits this Memorandum in Opposition to Sierra Club's Motion for Summary Judgment dated February 26, 2007. As Sierra Club's motion is premature and the material facts in Sierra Club's motion are disputed, Sierra Club is not entitled to judgment as a matter of law, and the Executive Secretary respectfully submits that the Air Quality Board should deny Sierra Club's Motion for Summary Judgment.

I. INTRODUCTION

On October 12, 2004, the Executive Secretary issued an Approval Order to Sevier Power Company to construct and operate a coal-fired power plant in Sevier County, Utah. On November 12, 2004, Sierra Club filed a Request for Agency Action ("RFA") to contest the Approval Order. The Executive Secretary anticipates that the Board will hold a hearing on the merits in September 2007. Sierra Club now moves for summary judgment on the new claim

which is the subject of its pending motion to amend. The Executive Secretary has filed an opposition to the motion to amend which is pending before the Board. Sierra Club's Motion for Summary Judgment should be denied because (1) Sierra Club erroneously relies on an inapplicable federal regulation; and (2) Sierra Club's statement of material facts is controverted such that Sierra Club cannot prevail as a matter of law.

Standard of Review

According to Utah Rule of Civil Procedure 56(c), summary judgment should be granted only when it is clear from undisputed facts, viewing evidence in light most favorable to the nonmoving party, that the opposing party cannot prevail. Warren v. Provo City Corp., 838 P.2d 1125, 1128 (Utah 1992); Lach v. Deseret Bank, 746 P.2d 802, 804 (Utah Ct. App. 1987). If there is any dispute as to any issue material to settlement of the controversy, summary judgment should not be granted. Holbrook Co. v. Adams, 542 P.2d 191, 193 (Utah 1975).

Although Sierra Club correctly cites the summary judgment standard under Rule 56, Sierra Club's additional argument that the appellate review standards set forth in Utah Code Ann. § 63-46b-16(4), apply to the Board's review of the Executive Secretary's action is misplaced. The standards in § 63-46b-16(4) only apply to the Utah Court of Appeals when it reviews the Board's decisions. Since Sierra Club seeks not judicial review in an appellate court, but rather contests an "initial order" of the Executive Secretary pursuant to Utah Admin. Code R307-103-3(1) and Utah Code § 63-46b-3(3), said standards do not apply. Rather, in this proceeding the Board sits as an adjudicative body similar to a trial court, evaluating evidence,

determining the facts from evidence and witness testimony, and making conclusions of law,[1] with the burden of proof being a preponderance of the evidence.[2]

II. ARGUMENT

A. Sierra Club's Reliance on the Federal Regulation is Misplaced

Sierra Club's proposed new claim (No. 10) alleges that "twenty eight months have passed since the Executive Secretary signed the Approval Order for the proposed plant," and that "the AO is now invalid, having expired automatically on or about April 12, 2006." *See* Sierra Club proposed First Amended Request for Agency Action at 9-10. In support of summary judgment on this claim, Sierra Club argues that as a matter of law, the Approval Order automatically expired 18 months after issuance. This is a faulty presumption based on a federal regulation that does not apply to this Approval Order. The federal regulation relied upon by Sierra Club, 40 C.F.R. § 52.21(r)(2), states in pertinent part that "[a]pproval to construct shall become invalid if construction is not commenced within 18 months of receipt of such approval . . . ." This regulation was not incorporated into Utah Admin. Code R307-405-19(1) until the March 2006 Air Quality Board meeting, to become effective in June 2006.[3] Because this federal regulation

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[1] *See* Utah Code Ann. § 63-46b-8, which governs the procedures for formal adjudicative proceedings. Because Sierra Club has filed a Request for Agency Action to contest an Initial Order of the Executive Secretary, this case is a formal adjudicative proceeding. *See also* § 63-46b-3 (commencement of adjudicative proceedings); Utah Admin. Code R307-103-4 ("[c]ontest of an initial order . . . shall be conducted as a formal proceeding"). By contrast, judicial review by the Court of Appeals or the Supreme Court employs different standards, as outlined in § 63-46b-16. It hardly seems plausible that the Legislature would provide one set of standards to govern adjudicative proceedings before the Air Quality Board and another to govern judicial review by the Court of Appeals if the Legislature intended both to apply the same standards. The bright line between these two standards is not blurred simply because these proceedings are adjudicative in nature.

[2] Walker v. Bd. of Pardons, 803 P.2d 1241 (Utah 1990) (stating that in administrative proceedings, the burden of proof is a preponderance of the evidence).

[3] *See* Exhibit A. This exhibit contains the amendments proposed to the Utah Air Quality Board at the March 2006 Air Quality Board meeting. It includes both the original rules and the proposed amendments that were ultimately adopted by the Board.

was not part of the rules at the time the Executive Secretary issued the Approval Order, the Approval Order is not subject to that regulation.

On the other hand, Condition 9 of the Approval Order and Utah Admin. Code R307-401-18 govern this question, and both endow the Executive Secretary with broad discretion to revoke the Approval Order if construction has not commenced after 18 months.[4] Neither of these provisions mandate an automatic expiration of the approval order.

Consequently, Sierra Club's legal arguments based upon this federal regulation are without merit.

B. <u>The Executive Secretary Disputes Sierra Club's Statement of Undisputed Facts</u>

Rule 7(c)(3)(B) of the Utah Rules of Civil Procedure requires that an opposition memorandum "contain a verbatim restatement of each of the moving party's facts that is controverted" and for each controverted fact, "provide an explanation of the grounds for any dispute . . . ."

In support of its Statement of Facts, Sierra Club attempts to rely upon the preliminary administrative record distributed on February 15, 2007, to show that certain actions did not occur. Because the record is only as broad as the allegations in Sierra Club's Request for Agency Action, there would be no reasonable expectation that the administrative record would contain any documentation concerning a post-permit 18 month review. Consequently, Sierra Club's reliance upon the preliminary administrative record to show what the Executive Secretary

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[4]Utah Admin Code R307-401-18 states that "[a]pproval orders issued by the Executive Secretary in accordance with the provisions of R307-401 will be reviewed 18 months after the date of issuance to determine the status of construction, installation, modification, relocation, or establishment. If a continuous plan of construction, installation, modification, relocation or establishment is not proceeding, the Executive Secretary may revoke the approval order."

may or may not have done in his R307-401-18 review is misplaced.

1. The Executive Secretary Disputes Sierra Club's Fact No. 3

The Executive Secretary disputes Sierra Club's Fact No. 3 which states "Eighteen months after the date of the AO - on or about April 12, 2006 - SPC did not submit the required notification of the status of construction."

The Executive Secretary disputes that "SPC did not submit the required notification of the status of construction." A review of the relevant time line demonstrates that the Sevier Power did in fact submit notification of the status of the construction. On November 17, 2005, Sevier Power sent a letter to the Executive Secretary explaining the current status of the SPC project. In that letter, Sevier Power stated that it had not commenced construction due to the ongoing litigation regarding its approval order. *See* Sevier Power Company letter to Executive Secretary attached hereto as Exhibit B. This letter provided the Executive Secretary with information regarding "status of construction, installation, modification, relocation, or establishment" of the SPC project.

Based on this information and upon knowledge of the permit conditions in Sevier Power's Approval Order, the Executive Secretary did not revoke the Approval Order. Whether SPC submitted the "required" notification is a question of law which the Board would determine by applying the law to the facts. Because Sierra Club has misstated the underlying facts, a genuine issue of material fact still exists, such that Sierra Club is not entitled summary judgment.

2. The Executive Secretary Disputes Sierra Club's Fact No. 4

Sierra Club's Fact No. 4 states "Eighteen months after the date of the AO – on or about

April 12, 2006 – the Executive Secretary made no determination regarding a revocation of the AO, nor whether an extension of the AO was justified."

Again, Sierra Club misstates the facts by relying on a preliminary administrative record which would not be expected to contain information on an 18 month review. *See* section B.1. above. Accordingly, a genuine issue of material fact exists on this question, and Sierra Club cannot prevail as a matter of law and is not entitled to summary judgment.

C. Sierra Club's Motion for Summary Judgment is Premature

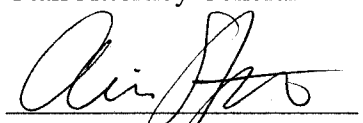
Sierra Club's Motion for Summary Judgment is premature because it is based upon a new claim that is the subject to a pending motion to amend. In the interest of expediency, however, the Executive Secretary is responding to the merits of Sierra Club's motion so that it can be heard and resolved at the April board meeting.

CONCLUSION

Based upon the foregoing, Sierra Club is not entitled to summary judgment, and its motion should therefore be denied.

Dated this 19th day of March, 2007.

MARK L. SHURTLEFF
Utah Attorney General



PAUL M. McCONKIE
CHRISTIAN C. STEPHENS
Assistant Attorneys General

CERTIFICATE OF SERVICE

I hereby certify that on the 19th day of March, 2007, a true and correct copy of the foregoing Executive Secretary's Motion for Partial Judgment on the Pleadings was mailed, postage prepaid, and/or emailed to the following:

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EXHIBIT A

State of Utah

Department of Environmental Quality

Dianne R. Nielson, Ph.D.
Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

Air Quality Board
John M. Veranth, *Chair*
Ernest E. Wessman , *Vice-Chair*
Nan Bunker
Stead Burwell
Jerry D. Grover
James R. Horrocks
Scott Lawson
Dianne R. Nielson
Wayne M. Samuelson
JoAnn B. Seghini
Don Sorensen
Richard W. Sprott,
Executive Secretary

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

DAQ-007-06

UTAH AIR QUALITY BOARD MEETING

Working lunch session will be held prior
12:00-1:00 p.m.

168 North 1950 West (Bldg #2) Room 101

FINAL AGENDA

Wednesday, March 8, 2006
1:30 p.m.

168 North 1950 West (Bldg #2) Room 101

I. Call-to-Order.

II. Date of the Next Air Quality Board Meeting: April 5, 2006.

III. Approval of the Minutes for February's Board Meeting.

IV. Approve Location and Travel for Sevier Power Hearing. Presented By Rick Sprott.

V. Final Adoption: Repeal and Re-enact R307-405, Permits: Major Sources in Attainment or Unclassified Areas (PSD); Amend R307-110-9 and State Implementation Plan Section VIII, Prevention of Significant Deterioration. Presented by Colleen Delaney and Jim Schubach.

VI. Final Adoption: Repeal and Re-enact R307-401, Permits: New and Modified Sources. Presented by Colleen Delaney and Jim Schubach.

VII. Final Adoption: Amend R307-410, Permits: Emission Impact Analysis. Presented by Colleen Delaney and Jim Schubach.

VIII. Propose for Public Comment: Repeal R307-413, Permits: Exemptions and Special Provisions; Amend R307-101-2 Definitions; Amend R307-325, Davis and Salt Lake Counties and Ozone Nonattainment Areas: Ozone Provisions. Presented By Colleen Delaney and Jim Schubach.

IX. Informational Items
A. $PM_{2.5}$ Proposed Standards. Presented by Cheryl Heying.
B. Recent SIP Approvals. Presented By Jan Miller.
C. Compliance. Presented by Jeff Dean.
D. HAPS. Presented by Robert Ford.
E. Monitoring. Presented by Bob Dalley.

In compliance with the American with Disabilities Act, individuals with special needs (including auxiliary communicative aids and services) should contact Charlene Lamph, Office of Human Resources at (801) 536-4413 (TDD 536-4414).

R307. Environmental Quality, Air Quality.
R307-405. Permits: Prevention of Significant Deterioration of Air Quality (PSD).[

]

R307-405-1. Purpose.

This rule implements the federal Prevention of Significant Deterioration (PSD) permitting program for major sources and major modifications in attainment areas and maintenance areas as required by 40 CFR 51.166. This rule does not include the routine maintenance, repair and replacement provisions that were stayed by the DC Circuit Court of Appeals on December 23, 2003, pending appeal. This rule does not include the clean unit and pollution control project provisions that were vacated by the DC Circuit Court of Appeals on June 24, 2005. This rule supplements, but does not replace, the permitting requirements of R307-401.

R307-405-2. Applicability.

(1) Except as provided in (2), the provisions of 40 CFR 52.21(a)(2), effective March 3, 2003, are hereby incorporated by reference.

(2)(a) The provisions in 40 CFR 52.21(a)(2)(iv)(e) are not incorporated by reference.

(b) The last sentence in 40 CFR 52.21(a)(2)(iv)(f) is not incorporated by reference.

(c) The provisions in 40 CFR 52.21(a)(2)(vi) are not incorporated by reference.

(3) Notwithstanding the exemptions in R307-401, any source that is subject to R307-405 is subject to the requirement to obtain an approval order in R307-401-5 through 8.

R307-405-3. Definitions.

(1) Except as provided in (2)below, the definitions contained in 40 CFR 52.21(b), effective March 3, 2003, are hereby incorporated by reference.

(2) "Air Quality Related Values," as used in analyses under 40 CFR 52.21(p) that is incorporated by reference in R307-405-17, means those special attributes of a Class I area, assigned by a federal land manager, that are adversely affected by air quality.

(3)(a)(i) "Major Source Baseline Date" means:

(A) in the case of particulate matter:

(I) for Davis, Salt Lake, Utah and Weber Counties, the date that EPA approves the PM10 maintenance plan that was adopted by the Board on July 6, 2005;

(II) for all other areas of the State, January 6, 1975;

(B) in the case of sulfur dioxide:

(I) for Salt Lake County, the date that EPA approves the sulfur dioxide maintenance plan that was adopted by the Board on January 5, 2005;

(II) for all other areas of the State, January 6, 1975; and

(C) in the case of nitrogen dioxide, February 8, 1988.

(ii) "Minor Source Baseline Date" means the earliest date after the trigger date on which a major stationary source or a major modification subject to 40 CFR 52.21 or R307-405 submits a complete application under the relevant regulations. The trigger date is:

(A) In the case of particulate matter and sulfur dioxide, August 7, 1977, and

(B) in the case of nitrogen dioxide, February 8, 1988.

(iii) The baseline date is established for each pollutant for which increments or other equivalent measures have been established if:

(A) the area in which the proposed source or modification would construct is designated as attainment or unclassifiable under section 107(d)(i)(D) or (E) of the Act for the pollutant on the date of its complete application under 40 CFR 52.21 or R307-405; and

(B) in the case of a major stationary source, the pollutant would be emitted in significant amounts, or, in the case of a major modification, there would be a significant net emissions increase of the pollutant.

(iv) Any minor source baseline date established originally for the TSP increments shall remain in effect and shall apply for purposes of determining the amount of available PM10 increments, except that the executive secretary shall rescind a minor source baseline date where it can be shown, to the satisfaction of the executive secretary, that the emissions increase from the major stationary source, or net emissions increase from the major modification, responsible for triggering that date did not result in a significant amount of PM10 emissions.

(b) In the definition of "baseline area" in 40 CFR 52.21(b)(15)(ii)(b) insert the words "or R307-405" after "Is subject to 40 CFR 52.21".

(c) "Reviewing Authority" means the executive secretary.

(d)(i) The term "Administrator" shall be changed to "executive secretary" throughout R307-405, except as provided in (ii).

(ii) The term "Administrator" shall be changed to "EPA Administrator" in the following incorporated sections:

(A) 40 CFR 52.21(b)(17),

(B) 40 CFR 52.21(b)(37)(i),

(C) 40 CFR 52.21(b)(43),

(D) 40 CFR 52.21(b)(48)(ii)(c),

(E) 40 CFR 52.21(b)(50)(i),

(F) 40 CFR 52.21(l)(2),

(G) 40 CFR 52.21(p)(2), <u>and</u>

(H) [~~the first reference to Administrator in 40 CFR 52.21(y)(4)(i),~~

~~(I) the second reference to Administrator in 40 CFR 52.21(y)(7), and~~

~~(J)~~]40 CFR 51.166(q)(2)(iv).

(e) The definition of "emissions unit" in 40 CFR 52.21(b)(7), effective January 6, 2004, is hereby incorporated by reference.

(f) The definition of "replacement unit" in 40 CFR 52.21(b)(33), effective January 6, 2004, is hereby incorporated by reference.

(g) The following paragraphs that refer to clean units and pollution control projects are not incorporated by reference:

(i) 40 CFR 52.21(b)(2)(iii)(h),

(ii) 40 CFR 52.21(b)(3)(iii)(b),

(iii) 40 CFR 52.21(b)(3)(vi)(d),

(iv) 40 CFR 52.21(b)(32), and

(v) 40 CFR 52.21(b)(42).

([~~3~~]4) "Heat input" means heat input as defined in 40 CFR 52.01(g).

([~~4~~]5) "Title V permit" means any permit or group of permits covering a Part 70 source that is issued, renewed, amended, or revised pursuant to R307-415.

([~~5~~]6) "Title V Operating Permit Program" means R307-415.

([~~6~~]7) The definition of "Good Engineering Practice (GEP) Stack Height" as defined in R307-410 shall apply in this rule.

([~~7~~]8) The definition of "Dispersion Technique" as defined in R307-410 shall apply in this rule.

R307-405-4. Area Designations.

(1) Pursuant to section 162(a) of the federal Clean Air Act, the following areas are designated as mandatory Class I areas:

(a) Arches National Park,

(b) Bryce Canyon National Park,

(c) Canyonlands National Park,

(d) Capitol Reef National Park, and

(e) Zion National Park.

(2) Pursuant to section 162(b) of the federal Clean Air Act, all other areas in Utah are designated as Class II unless designated as nonattainment areas.

(3) No areas in Utah are designated as Class III.

R307-405-5. Area Redesignation.

Any person may petition the Board to change the classification of an area designated under R307-405-4, except for mandatory Class I areas designated under R307-405-4(1).

(1) The petition shall contain a discussion of the reasons for the proposed redesignation, including a satisfactory description and analysis of the health, environmental, economic and social and energy effects of the proposed re[~~s~~]designation.

(2) The petition shall contain a demonstration that the proposed redesignation meets the criteria outlined in Section VIII of the State Implementation Plan and 40 CFR 51.166(e) and (g).

R307-405-6. Ambient Air Increments.

The provisions of 40 CFR 52.21(c), effective March 3, 2003, are hereby incorporated by reference.

R307-405-7. Ambient Air Ceilings.

The provisions of 40 CFR 52.21(d), effective March 3, 2003, are hereby incorporated by reference.

R307-405-8. Exclusions from Increment Consumption.

(1) The following concentrations shall be excluded in determining compliance with a maximum allowable increase:

(a) concentrations attributable to the increase in emissions from stationary sources which have converted from the use of petroleum products, natural gas, or both by reason of an order in effect under section 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) over the emissions from such sources before the effective date of such an order;

(b) concentrations attributable to the increase in emissions from sources which have converted from using natural gas by reason of a natural gas curtailment plan in effect pursuant to the Federal Power Act over the emissions from such sources before the effective date of such plan;

(c) concentrations of particulate matter attributable to the increase in emissions from construction or other temporary emission-related activities of new or modified sources;

(d) the increase in concentrations attributable to new sources outside the United States over the concentrations attributable to existing sources which are included in the baseline concentration; and

(e) concentrations attributable to the temporary increase in emissions of sulfur dioxide, particulate matter, or nitrogen dioxides from stationary sources which are affected by plan revisions approved by the EPA Administrator as meeting the criteria specified in 40 CFR 51.166(f)(4). The temporary increase shall not exceed 2 years in duration unless a longer time is approved by the EPA Administrator. This exclusion is not renewable.

(2) No exclusion of concentration under (1)(a) or (b) above shall apply more than five years after the effective date of the order to which paragraph (1)(a) refers or the plan to which paragraph (1)(b) refers, whichever is applicable. If both such order and plan are applicable, no such exclusion shall apply more than five years after the later of such effective dates.

(3) No exclusion under (1)(e) shall apply to an emission increase from a stationary source which would:

(a) impact a Class I area or an area where an applicable increment is known to be violated; or

(b) cause or contribute to a violation of the national ambient air quality standards.

R307-405-9. Stack Heights.

The provisions of 40 CFR 52.21(h), effective March 3, 2003, are hereby incorporated by reference.

R307-405-10. Exemptions.

(1) The provisions of 40 CFR 52.21(i)(1)(vi) through (viii), effective March 3, 2003, are hereby incorporated by reference.

(2) The provisions of 40 CFR 52.21(i)(2) through (5), effective March 3, 2003, are hereby incorporated by reference.

R307-405-11 Control Technology Review.

The provisions of 40 CFR 52.21(j), effective March 3, 2003, are hereby incorporated by reference.

R307-405-12. Source Impact Analysis.

The provisions of 40 CFR 52.21(k), effective March 3, 2003, are hereby incorporated by reference.

R307-405-13. Air Quality Models.

The provisions of 40 CFR 52.21(l), effective March 3, 2003, are hereby incorporated by reference.

R307-405-14. Air Quality Analysis.

(1) The provisions of 40 CFR 52.21(m)(1)(i) through (iv), (vi), and (viii), effective March 3, 2003, are hereby incorporated by reference.

(2) The provisions of 40 CFR 52.21(m)(2) and (3), effective March 3, 2003, are hereby incorporated by reference.

R307-405-15. Source Information.

The provisions of 40 CFR 52.21(n), effective March 3, 2003, are hereby incorporated by reference.

R307-405-16. Additional Impact Analysis.

The provisions of 40 CFR 52.21(o), effective March 3, 2003, are hereby incorporated by reference.

R307-405-17. Sources Impacting Federal Class I Areas: Additional Requirements.

(1) The provisions of 40 CFR 52.21(p), effective March 3, 2003, are hereby incorporated by reference.

(2) The executive secretary will transmit to the EPA Administrator a copy of each permit application relating to a major stationary source or major modification and provide notice to the EPA Administrator of every action related to the consideration of such permit.

R307-405-18. Public Participation.

(1) Except as provided in (2), the provisions of 40 CFR 51.166(q)(1) and (2), effective March 3, 2003, are hereby incorporated by reference.

(2) The phrase "within a specified time period" in 40 CFR 51.166(q)(1) shall be replaced with the phrase "within 30 days of receipt of the PSD permit application".

R307-405-19. Source Obligation.

(1) Except as provided in (2) below, the provisions of 40 CFR 52.21(r), effective March 3, 2003, are hereby incorporated by reference.

(2)[~~(a)~~] The parenthetical phrase in the first sentence in 40 CFR 52.21(r)(6) shall be changed to read "(other than projects at a source with a PAL)."[

~~(b) The reference to "70.4(b)(3)(viii) of this chapter" in 40 CFR 52.21(r)(7) shall be changed to "R307-415-7i".~~]

R307-405-20. Innovative Control Technology.

(1) Except as provided in (2), the provisions of 40 CFR 52.21(v), effective March 3, 2003, are hereby incorporated by reference.

(2)(a) The reference to "40 CFR 124.10" in 40 CFR 52.21(v)(1) shall be changed to "R307-405-18".

(b) 40 CFR 52.21(v)(2) shall be changed to read "The executive secretary shall, with the consent of the governors of other affected states, determine that the source or modification may employ a system of innovative control technology, if:".

R307-405-21. Actuals PALs.

(1) Except as provided in (3), the provisions of 40 CFR 52.21(aa)(1) through (5) and (7) through (15), effective March 3, 2003, are hereby incorporated by reference.

(2) The provisions of 40 CFR 52.21(aa)(6), effective January 6, 2004, are hereby incorporated by reference.

(3)(a) The reference to "51.165(a)(3)(ii) of this chapter" in 40 CFR 52.21(aa)(4)(ii) shall be changed to "R307-403".

(b) The reference to "51.165(a)(3)(ii) of this chapter" in 40 CFR 52.21(aa)(8)(ii)(2) shall be changed to "R307-403".

(c) The references to "70.6(a)(3)(iii)(B) of this chapter" in 40 CFR 52.21(aa)(14)(ii) shall be changed to "R307-415-6a(3)(c)(ii)".

(d) The date of "March 3, 2003" in 40 CFR 52.21(aa)(15)(i) and (ii) shall be changed to "the effective date of this rule".

R307-405-22. Banking of Emission Offset Credit in PSD Areas.

Banking of emission offset credits in PSD areas will be permitted. To preserve banked emission reductions the executive secretary must identify them in either the Utah SIP or an order. The executive secretary will provide a registry to identify the person, private entity, or government authority that has the right to use or allocate the banked emission reduction and to record any transfer of or lien on these rights.

KEY: air pollution, PSD, Class I area
2006
Notice of Continuation August 11, 2003
19-2-104

R307. Environmental Quality, Air Quality.
R307-405. Permits: Prevention of Significant Deterioration of Air Quality (PSD).
R307-405-1. Definitions.

The following additional definitions apply to R307-405:

"Baseline Area" means any intrastate area (and every part thereof) designated as attainment or unclassifiable under Section 107(d)(1)(D) or (E) of the federal Clean Air Act in which the major source or major modification establishing the minor source baseline date would construct or would have an air quality impact equal to or greater than 1 ug/m3 (annual average) of the pollutant for which the minor source baseline date is established.

(1) Area redesignations under section 107(d)(1) (D) or (E) of the federal Clean Air Act cannot intersect or be smaller than the area of impact of any major stationary source or major modification which:

(a) Establishes a minor source baseline date; or

(b) Is subject to 40 CFR 52.21 or R307-405, and would be constructed in the same state as the state proposing the redesignation.

"Baseline Concentration" means that ambient concentration level which exists in the baseline area at the time of the applicable minor source baseline date.

"Major Modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Clean Air Act.

(1) Any net emissions increase that is significant for volatile organic compounds shall be considered significant for ozone.

(2) A physical change or change in the method of operation shall not include:

(a) routine maintenance, repair, and replacement;

(b) use of an alternative fuel or raw material by reason of an order under section 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation), or by reason of a natural gas curtailment plan pursuant to the Federal Power Act;

(c) use of an alternative fuel by reason of an order or rule under section 125 of the Clean Air Act;

(d) use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;

(e) use of an alternative fuel or raw material by a source which:

(i) the source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any federally enforceable permit condition; or

(ii) the source is approved to use;

(f) an increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition;

(g) any change in ownership at a source

(h) the addition, replacement or use of a pollution control project at an existing electric utility steam generating unit, unless the executive secretary determines that such addition, replacement, or use renders the unit less environmentally beneficial, or except:

(i) when the executive secretary has reason to believe that the pollution control project would result in a significant net increase in representative actual annual emissions of any criteria pollutant over levels used for that source in the most recent air quality impact analysis in the area conducted for the purpose of Title I of the Clean Air Act, if any, and

(ii) the executive secretary determines that the increase will cause or contribute to a violation of any national ambient air quality standard or PSD increment, or visibility limitation.

(i) the installation, operation, cessation, or removal of a temporary clean coal technology demonstration project, provided that the project complies with:

(i) the Utah State Implementation Plan; and

(ii) other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(j) the installation or operation of a permanent clean coal technology demonstration project that constitutes repowering, provided that the project does not result in an increase in the potential to emit of any regulated pollutant emitted by the unit. This exemption shall apply on a pollutant-by-pollutant basis.

(k) the reactivation of a very clean coal-fired electric utility steam generating unit.

"Major Source" means:

(1) any of the following sources of air pollutants which emits, or has the potential to emit, 100 tons per year or more of any pollutant subject to regulation under the Clean Air Act: Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), kraft pulp mills, portland cement plants, primary zinc smelters, iron

and steel mill plants, primary aluminum ore reduction plants, primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries, lime plants, phosphate rock processing plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion plants, sintering plants, secondary metal production plants, chemical process plants, fossil fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants, and charcoal production plants;

(2) any other source which emits, or has the potential to emit, 250 tons per year or more of any air pollutant; or

(3) a source which does not otherwise qualify as a major source as defined in this paragraph, but which is physically changed, which change itself would constitute a major source.

(4) a source which is major for volatile organic compounds is major for ozone.

(5) The fugitive emissions and fugitive dust of a stationary source shall not be included in determining for any of the purposes of this section whether it is a major stationary source, unless the source belongs to one of the following categories of stationary sources:

(a) Coal cleaning plants (with thermal dryers);
(b) Kraft pulp mills;
(c) Portland cement plants;
(d) Primary zinc smelters;
(e) Iron and steel mills;
(f) Primary aluminum ore reduction plants;
(g) Primary copper smelters;
(h) Municipal incinerators capable of charging more than 250 tons of refuse per day;
(i) Hydrofluoric, sulfuric, or nitric acid plants;
(j) Petroleum refineries;
(k) Lime plants;
(l) Phosphate rock processing plants;
(m) Coke oven batteries;
(n) Sulfur recovery plants;
(o) Carbon black plants (furnace process);
(p) Primary lead smelters;
(q) Fuel conversion plants;
(r) Sintering plants;
(s) Secondary metal production plants;

(t) Chemical process plants;

(u) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

(v) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

(w) Taconite ore processing plants;

(x) Glass fiber processing plants;

(y) Charcoal production plants;

(z) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input;

(aa) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Federal Clean Air Act.

R307-405-2. Area Designations.

All areas of the State shall be designated as Class I, II, or III.

(1) Pursuant to section 162(a) of the federal Clean Air Act the following areas are designated as mandatory Class I:

(a) Arches National Park

(b) Bryce Canyon National Park

(c) Canyonlands National Park

(d) Capitol Reef National Park

(e) Zion National Park

(2) Pursuant to section 162(b) of the federal Clean Air Act, all other areas of the State are designated as Class II unless redesignated as provided in R307-405-3 or are designated as nonattainment areas.

R307-405-3. Area Redesignation.

(1) Within the restrictions and requirements of this paragraph, the Board may submit to the Governor for decision a recommendation to redesignate areas from any class to any other class.

(2) In accordance with Section 162(a) of the federal Clean Air Act, areas designated as Class I under R307-405-2 may not be redesignated.

(3) In accordance with Section 164(a) of the federal Clean Air Act, the following areas may be redesignated only as Class I or II.

(a) An area which as of August 7, 1977, exceeded 10,000 acres in size and was a national monument, a national primitive area, a national preserve, a national recreation area, a national wild and scenic river, a national wildlife refuge, a national lakeshore or seashore; and

(b) A national park or national wilderness area established after August 7, 1977, which exceeds 10,000 acres in size.

(4) Except as provided in (2), (3) and (6) the Board may submit to the Governor for decision a recommendation to redesignate areas of the State as Class III if:

(a) There has been compliance with the requirements of (5) below.

(b) Such redesignation will not cause, or contribute to, concentrations of any air pollutant which exceed any maximum allowable increase permitted under the classification of any other area or any national ambient air quality standard; and

(c) Any permit application for any major source or major modification which could receive an approval order only if the area in question were redesignated as Class III, and any material submitted as part of that notice of intent were available, insofar as practicable, prior to any public hearing or redesignation.

In accordance with Section 164 of the federal Clean Air Act, redesignations to Class III may be approved by the Governor only after consultation with appropriate committees of the legislature and if units of local government representing a majority of the residents of the proposed area to be redesignated enact ordinances concurring in the redesignation.

(5) Prior to submittal to the Governor of a recommendation to redesignate any area:

(a) Notice shall be published in each daily newspaper in the affected area and written notice shall be made to local government units, other states, Indian governing bodies, Federal Land Managers whose lands may be affected by the proposed redesignation and public hearings shall be conducted in the affected areas. Such notice shall be made at least 30 days prior to the public hearing and include a statement of the availability of the discussion outlined in (b) below. Prior to the issuance of a notice under this paragraph respecting the redesignation of any Federal lands, a written notice shall be given to the appropriate Federal Land Manager who shall be afforded opportunity (not to exceed 60 days) to confer with the Board respecting the redesignation and to submit written comments and recommendations. In recommending redesignation of any area with respect to which a Federal Land Manager has submitted comments the Board shall publish a list of any inconsistency between such redesignation and such comments and recommendations together with the reasons for recommending

such redesignation against the recommendation of the Federal Land Manager; and

(b) A discussion of the reasons for the proposed redesignation, including a satisfactory description and analysis of the health, environmental, economic and social and energy effects of the proposed redesignation, will be prepared and made available for public inspection at least 30 days prior to the hearing. Any person who petitions the Board for redesignation of an area may be required to prepare and submit this analysis to the Board.

(6) Lands within the exterior boundaries of reservations of federally recognized Indian Tribes may be redesignated only by the appropriate Indian body as provided in Section 164 of the Clean Air Act.

R307-405-4. Increments and Ceilings.

(1) In Class I, II, or III areas, the maximum allowable increases in concentrations of sulfur dioxide, nitrogen dioxide and particulate matter over baseline concentrations of such pollutants are limited to the following:

TABLE

(1)Maximum Allowable Increase (ug/m3)

Pollutant	Class I	Class II	Class III
PM10:			
Annual Arithmetic Mean	4	17	34
24-hr. Maximum	8	30	60
Sulfur Dioxide:			
Annual Arithmetic Mean	2	20	40
24-hr. Maximum	5	91	182
3-hr. Maximum	25	512	700
Nitrogen Dioxide:			
Annual Arithmetic Mean	2.5	25	50

Note (1): At any one location, the maximum allowable increase for other than the annual period may be exceeded once each year. For any period other than the annual period, the applicable maximum allowable increase may be exceeded during one such period per year at any one location.

(2) Variances to Class I areas will be allowed only after compliance with the requirements of and within the increments provided in Section 165 of the federal Clean Air Act, or in the case of PM10 increments, only after compliance with the Title 40 of the Code of Federal Regulations, Section

51.166(p)(4) (as amended-see the June 3, 1993 Federal Register notice, 58 FR 31637) which is hereby incorporated by reference.

(3) In any area, no resultant concentration of any air pollutant shall exceed the concentration permitted under either the national secondary or primary ambient air quality standard whichever concentration is lowest for the pollutant for a period of exposure.

(4) Exclusions from increment consumption. The following concentrations shall be excluded in determining compliance with a maximum allowable increase:

(a) Concentrations attributable to the increase in emissions from sources which have converted from:

(i) the use of petroleum products, natural gas, or both by reason of an order in effect under sections 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974; or

(ii) using natural gas by reason of a natural gas curtailment plan in effect pursuant to the Federal Power Act, over the emissions from such sources before the effective date of such an order or plan.

No exclusion of such concentrations shall apply more than five years after the effective date of the order or the plan. If both an order and plan are applicable, no such exclusion shall apply more than five years after the later of such effective dates.

(b) Concentrations of PM10 attributable to the increase in emissions from construction or other temporary emission-related activities.

(c) Concentrations attributable to the temporary increase in emissions of sulfur dioxide, nitrogen oxides or PM10 from sources which are affected by plan revisions approved by EPA as meeting the criteria specified in 40 CFR 51.166(f)(4).

R307-405-5. Baseline Concentration and Date.

(1) Baseline concentration. A baseline concentration is determined for each pollutant for which a minor source baseline date is established and shall include:

(a) The actual emissions representative of sources in existence on the applicable minor source baseline date except as provided in (2) below;

(b) The allowable emissions of major sources which commence construction before the major source baseline date, but were not in operation by the applicable minor source baseline date.

(2) The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s):

(a) actual emissions from any major source on which construction commenced after the major source baseline date, and

(b) actual emissions increases and decreases at any source occurring after the minor source baseline date.

(3) Baseline date. The minor source baseline date is established for each pollutant for which increments or other equivalent measures have been established if:

(a) the area in which the proposed source or modification would construct is designated as attainment or unclassifiable under section 107(d)(i)(D) or (E) of the federal Clean Air Act for the pollutant on the date of its complete application under 40 CFR 52.21, or R307-405; and

(b) in the case of a major source the pollutant would be emitted in significant amounts, or, in the case of a major modification, there would be a significant net emissions increase of the pollutant. With respect to particulate matter, significant shall mean significant for PM10.

(4)(a) Any minor source baseline date established originally for increments of total suspended particulates shall remain in effect and shall apply for purposes of determining the amount of available PM10 increments, except that the executive secretary may rescind any such minor source baseline date where it can be shown to the executive secretary's satisfaction that the emissions increase from the major stationary source or the net emissions increase from the major modification responsible for triggering that date did not result in a significant amount of PM10 emissions.

(b) Any baseline area established originally for the increments of total suspended particulates shall remain in effect and shall apply for purposes of determining the amount of available PM10 increments, except that such baseline area shall not remain in effect if the executive secretary rescinds the corresponding minor source baseline date in accordance with(a) above.

R307-405-6. PSD Areas - New Sources and Modifications.

(1) Emission Limitations. Any source constructed or modified in a PSD area must meet all applicable emissions requirements of R307 and the Utah State Implementation Plan. A proposed source or modification which is not a major source or major modification may be approved without meeting the requirements in (2) below, provided such source meets all other applicable requirements of these regulations. The

emission limitations shall be stated as conditions of the approval order.

(2) Major Source and Major Modification Review. Every new major source or major modification must be reviewed by the Executive Secretary to determine the air quality impact of the source to include a determination whether the source will cause or contribute to a violation of the maximum allowable increases or the NAAQS in any area. The determination of air quality impact will be made as of the source's projected start-up date. Such determination shall take into account all allowable emissions of approved sources or modifications whether constructed or not, and, to the extent practicable, the cumulative effect on air quality of all sources and growth in the affected area.

(a) In addition to meeting all other requirements of these regulations, any major source or major modification which would be constructed in a PSD area, shall:

(i) Provide the following additional information with the notice of intent required pursuant to R307-401:

(A) An analysis of the air quality impact of the source or modification and a demonstration that allowable emissions increases from the source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), will not cause or contribute to a violation of any maximum allowable increase over the baseline concentration in any area or any NAAQS in any area.

(B) An analysis of ambient air quality in the affected area for each pollutant that a new source would have the potential to emit in a significant amount, and for each pollutant for which a modification would result in a significant net emissions increase. With respect to any such pollutant for which no NAAQS exists, the analysis shall contain such air quality monitoring data as the Executive Secretary determines is necessary to assess ambient air quality for that pollutant in any area that the emissions of that pollutant would affect. With respect to any such pollutant (other than non-methane hydrocarbons) for which such a NAAQS does exist, the analysis shall contain continuous air quality monitoring data gathered for purposes of determining whether emissions of that pollutant would cause or contribute to a violation of the standard or any maximum allowable increase in any area that the emissions of that pollutant would affect. In general, the continuous air quality monitoring data that is required shall have been gathered over a period of at least one year and shall represent at least the year preceding receipt of the notice of intent, except that, if the Executive Secretary determines

that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year (but not to be less than four months), the data that is required shall have been gathered over at least that shorter period. Any data used in the analysis must be gathered using EPA reference methods or equivalent and quality assurance procedures equivalent to 40 CFR Part 58, Appendix B. A monitoring plan will be submitted to the Executive Secretary for approval prior to data collection. The Executive Secretary may grant exceptions or modifications to these monitoring requirements when not inconsistent with federal law.

(C) Upon request of the Executive Secretary, the air quality impact of the source or modification, including meteorological and topographical data necessary to estimate such impact; and the air quality impact of any or all general commercial residential, industrial, and other growth which has occurred since the minor source baseline date in the area the source or modification would affect.

(D) An analysis of the air quality related impact of the source or modification including an analysis of the impairment to visibility, soils, and vegetation and the projected air quality impact from general commercial, residential, industrial, and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.

(ii) After construction of the source or modification, conduct such ambient air quality monitoring as the Executive Secretary determines may be necessary to establish the effect which the emissions from the source or modification may have on the air quality in any area.

(b) If the Executive Secretary finds that the emissions from a proposed major source or major modification would cause a violation of any maximum allowable increase over the baseline concentration in any area, the Executive Secretary shall approve the proposed source if and only if:

(i) the new source or modification is required to meet a more stringent emission limitation sufficient to avoid a violation of the maximum allowable increase and/or

(ii) the new source or modification has acquired sufficient offset to avoid a violation of the maximum allowable increase, and

(iii) the new emission limitations for the proposed source and for any affected existing sources are enforceable.

(c) If the Executive Secretary finds that the emissions from a proposed major source or major modification would

contribute to a known violation of any maximum allowable increase over the baseline concentration in any area, the Executive Secretary shall approve the proposed source if and only if:

(i) the new source or modification has acquired sufficient emission offset so as to provide a positive net air quality benefit in the affected area, and

(ii) any new emission limitations for affected existing sources are enforceable.

(3) The requirements of (2)(a) above shall not apply to a major source or major modification if:

(a) The source is a portable stationary source which has previously received a permit under this paragraph, and

(i) The owner or operator proposes to relocate the source and emissions of the source at the new location would be temporary; and

(ii) The emissions from the source would not exceed its allowable emissions; and

(iii) The emissions from the source would impact no Class I area and no area where an applicable increment is known to be violated;

(b) The source or modification would be a non-profit health or non-profit educational institution and the Board approves a request that it be exempt from those requirements.

(c) The source or modification would be a major source or major modification only if fugitive emission and fugitive dust, to the extent quantifiable, are considered in calculating the potential to emit of the source or modification and the source does not belong to any of the following categories:

(i) Coal cleaning plants (with thermal dryers);

(ii) Kraft pulp mills;

(iii) Portland cement plants;

(iv) Primary zinc smelters;

(v) Iron and steel mills;

(vi) Primary aluminum or reduction plants;

(vii) Primary copper smelters;

(viii) Municipal incinerators capable of charging more than 250 tons of refuse per day;

(ix) Hydrofluoric, sulfuric, or nitric acid plants;

(x) Petroleum refineries;

(xi) Lime plants;

(xii) Phosphate rock processing plants;

(xiii) Coke oven batteries;

(xiv) Sulfur recovery plants;

(xv) Carbon black plants (furnace process);

(xvi) Primary lead smelters;

(xvii) Fuel conversion plants;
(xviii) Sintering plants;
(xix) Secondary metal production plants;
(xx) Chemical process plants;
(xxi) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;
(xxii) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;
(xxiii) Taconite ore processing plants;
(xxiv) Glass fiber processing plants;
(xxv) Charcoal production plants;
(xxvi) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input;
(xxvii) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the federal Clean Air Act.

(d) With respect to a particular pollutant, the allowable emissions of that pollutant from the source, or the net emissions increase of that pollutant from the modification:

(i) would impact no Class I area and no area where an applicable increment is known to be violated, and

(ii) would be temporary.

(4) The requirements of (2)(a) above as they relate to any maximum allowable increase for a Class II area shall not apply to a major modification at a source that was in existence on March 1, 1978, if the net increase in allowable emissions for each pollutant from the modification after the application of best available control technology would be less than 50 tons per year.

(5)(a) The requirements of (2)(a)(i)(A) above pertaining to the impact analysis shall not apply to a source or modification with respect to any maximum allowable increase for nitrogen oxides if the owner or operator of the source or modification submitted a notice of intent before October 15, 1990, and the Executive Secretary subsequently determined that the notice of intent as submitted before that date was complete.

(b) The requirements of (2)(a)(i)(A) above concerning an analysis of the maximum allowable increase over the baseline concentration shall not apply to a stationary source or modification with respect to any maximum allowable increase for PM10 if the owner or operator of the source or modification submitted an application for a permit before December 15, 1994, and the executive secretary subsequently determined that the application as submitted before that date

was complete. Instead, the applicable requirements shall be with respect to the maximum allowable increases for total suspended particulates as in effect on the date the application was submitted. These increments were, for the annual geometric mean: 5, 19, and 37 micrograms/cubic meter for Class I, II and III areas respectively and, for the 24-hour maximum: 10, 37 and 75 micrograms/cubic meter for Class I, II and III areas respectively.

(6) Exemption - Monitoring Requirement

(a) The Executive Secretary may grant exceptions or modifications to the monitoring requirements in (2)(a)(i)(B) above which are not inconsistent with federal law.

(b) The Executive Secretary may exempt a stationary source or modification from the requirements of (2)(a)(i)(B) above with respect to monitoring for a particular pollutant if:

(i) The emissions increase of the pollutant from the new source or the net emissions increase of the pollutant from the modification would cause, in any area, air quality impacts less than the following amounts:

Carbon monoxide - 575 ug/m3, 8-hour average;
Nitrogen dioxide - 14 ug/m3, annual average;
PM10 - 10 micrograms/cubic meter, 24-hour average;
Sulfur dioxide - 13 ug/m3, 24-hour average;
Lead - 0.1 ug/m3, 24-hour average;
Mercury - 0.25 ug/m3, 24-hour average;
Beryllium - 0.0005 ug/m3, 24-hour average;
Ozone - No de minimis air quality level is provided for ozone. However, any proposed source or modification subject to PSD with net increase of 100 tons per year or more of volatile organic compounds subject to PSD would be required to perform an ambient impact analysis including the gathering of ambient air quality data;
Fluorides - 0.25 ug/m3, 24-hour average;
Vinyl chlorides - 15 ug/m3, 24-hour average;
Total reduced sulfur - 10 ug/m3, 1-hour average;
Hydrogen sulfide - 0.04 ug/m3, 1-hour average;
Reduced sulfur compounds - 10 ug/m3, 1-hour average; or

(ii) The concentrations of the pollutant in the area that the source or modification would affect are less than the concentrations listed or the pollutant is not listed in (i) above.

R307-405-7. Increment Violations.

Where the Board determines that an increment under R307-405-4 is violated, the Board shall promulgate a plan and implement regulations to eliminate the violation.

R307-405-8. Banking of Emission Offset Credit in PSD Areas.

Banking of emission offset credits in PSD areas will be permitted. To preserve banked emission reductions the Executive Secretary must identify them in either the Utah SIP or an order and shall provide a registry to identify the person, private entity, or government authority that has the right to use or allocate the banked emission reduction and to record any transfer of or lien on these rights.

KEY: air pollution, PSD, Class I area
July 12, 2001
Notice of Continuation August 11, 2003
19-2-104

EXHIBIT B

RECEIVED
NOV 1 8 2005
AIR QUALITY

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November 17, 2005

John D. Jenks, Engineer
Division of Air Quality
150 North 1959 West
PO Box 144820
Salt Lake City, UT 84114-4820

Re: Approval Order: Sevier Power Company's 270 MW Coal-Fired Power Plant, Sevier County- CDS A; ATT: PSD: NSPS, MACT, HAPs, Title IV Major, Title V Major
Project Code: DAQE-AN2529001-04

Dear John Jenks:

Our firm represents the Sevier Power Company and they have asked me to give you an update on what has happened since the Approval Order (the "AO") referenced above was issued on October 12, 2004. In short, before the ink on the AO was dry, it was appealed. A battle over standing was fought by the Parties before the Utah Air Quality Board (the "Board"). The Board determined that the Sierra Club and the Grand Canyon Trust did not have standing. These parties have appealed the Board's ruling on standing to the Court of Appeals. The Court of Appeals has denied motions from the Sierra Club and Grand Canyon Trust to enlarge the record and to stay the Board's formal adjudication of the Sevier County Citizens For Clean Air and Clean Water's Request For Agency Action. These events have taken place over the following time line:

1. October 12, 2004, The Executive Secretary issued the above mentioned Approval Order for the Sevier Power Company.

2. November 1, 2004, the Sevier County Citizens For Clean Air and Water (the "Sevier County Citizens"), filed a combined Petition For Standing to Intervene and a Request For Agency Action on the issuance of the AO. This document was filed with the Board on November 4, 2004.

3. November 12, 2004, the Sierra Club and Grand Canyon Trust (collectively the "Sierra Club") filed a Request For Agency Action and a Statement of Standing and Petition to Intervene.

4. January 4, 2005, PacifiCorp also filed a Petition to Intervene and a Statement of Standing.

5. January 6, 2005, the Board issued a "Notification of Further Proceedings" which established a schedule for briefing and reply briefing with a hearing before the Board set for March, which was subsequently reset for hearing on April 13, 2005. The parties filed extensive briefs pursuant to this schedule.

6. April 13, 2005, the Board conducted a hearing on the standing of each of the petitioning parties. The Executive Secretary and the Sevier Power Company were granted standing by Board Rule as the main parties. The Citizens For Sevier County, the Sierra Club and Utah Power may only intervene if granted permission by the Board. After the matter was fully heard, the Board determined that it would grant standing to the Sevier County Citizens, and deny standing to both the Sierra Club and Utah Power. The Board also granted amicus status to both the Sierra Club and Utah Power. The Board mentioned that it would put its ruling in written form and approve the written draft as the final order at its next meeting in May.

7. May 12, 2005, the Board, after a review of its written order prepared by Counsel Fred Nelson, adopted the May 12, 2005 as its written order which both granted and denied standing to the respective parties as mentioned above.

8. May 17, 2005, the Sierra Club filed its Petition for Review with the Court of Appeals seeking a reversal of the May 12th Board decision denying standing. The Sierra Club also filed a Motion to Stay the Sevier County Citizens' Request For Agency Action pending its appeal to the Court of Appeals.

9. June 1, 2005, the Board held a hearing on the Sierra Club's Motion to Stay the Request For Agency Action. After the matter had been briefed and all parties had presented information to the Board, it determined that it would not stay the remaining Request For Agency Action filed by the Sevier County Citizens. This order was signed by the Chairman of the Board on June 6, 2005. A schedule for Request For Agency review was adopted which provided a time for answers to be filed, discovery, motions, and a proposed hearing in December, 2005 was also adopted by the Board.

   Since the Sierra Club filed its Petition For Review with the Court of Appeals, there are now two different tracts of appeal being pursued by the Sierra Club and the Sevier County Citizens. I will attempt to weave both appeals into one common time line.

10. June 10, 2005 (DAQ), the Executive Secretary and the Sevier Power Company filed with the Board their response to the Citizens November 1, 2004 Request For Agency Action.

11. June 23, 2005 (COA), the Board filed with the Appellate Court its revised record index identifying the record of the Agency in making its decision to deny standing.

12. June 24, 2005 (COA), the Sevier Power Company filed its Motion to Intervene in the Court of Appeals review of the Board's decision on standing. Intervention was granted by the Court of Appeals.

13. July 1, 2005 (COA), the Sierra Club filed a Motion For A Stay Pending Review, with supporting memorandum, requesting the Court of Appeals to stay the administrative proceedings in the DAQ.

14. July 18, 2005 (COA), the Executive Secretary filed a Motion to Intervene in the Sierra Club's Motion for the Stay. Its request for intervene was granted by the Court and the Executive Secretary filed briefs in opposition to the Sierra Club's Motion for a Stay and Motion to Expand the Record.

15. July 19, 2005 (COA), the Sierra Club filed a Motion to Supplement Record with Supporting Memorandum, and a Motion for Enlargement of Time to File Opening Brief.

16. July 28, 2005 (COA), a mediation conference was held at the Court of Appeals. All of the parties were present and participated in the conference. Subsequently, the Court Appointed Mediator issued an order releasing the parties from further participation in mediation.

17. August 29, 2005 (COA), the Court of Appeals, after reviewing the Parties' memorandums on the various motions submitted by the Sierra Club, issued its order denying the Sierra Club's Motion to Stay and also denying the Sierra Club's Motion to Supplement the Record.

18. August 30, 2005 (COA), the Court of Appeals issued a scheduling order requiring the Sierra Club's Brief to be filed by October 3, 2005. It was filed timely. The Executive Secretary and the Sevier Power Company filed their responsive briefs on November 2, 2005. The Sierra Club has an opportunity to file one more brief by December 2, 2005. After all of the briefs have been filed, the Court of Appeals will review the briefs and determine whether a hearing should be scheduled. They did not hold a hearing before denying the two previous motions of the Sierra Club. There could still be a hearing after the briefing is completed by December 2, 2005 and then after the hearing, the Court would then issue its decision on the Board's denial of standing to the Sierra Club. A final decision from the COA is still a number of months in the future.

19. September 23, 2005 (DAQ), the Executive Secretary served a set of interrogatories and request for the production of documents on the Sevier County Citizens.

20. October 3, 2005 (DAQ), the Executive Secretary filed a Motion to Compel because of the alleged failure of the Sevier County Citizens group to respond to the Interrogatories and

Requests For Production of Documents.

21. November 2, 2005 (DAQ), the Board held a hearing on the Executive Secretary's Motion to Compel. The Parties were present and submitted information to the Board about the lack of Discovery response from the Sevier County Citizens Group. After hearing from all parties, the Board granted the Motion to Compel and entered a written Order Regarding The Executive Secretary's Motion to Compel Discovery.

22. January 2006 (DAQ), this would be the earliest that a hearing on the Request For Agency Action could be held; however, at this meeting the Parties, including the Executive Secretary and the Sevier Power Company, may request the Board to rule on Preliminary Motions, and that the actual hearing, if necessary may more likely be scheduled for the February 2006 Board Meeting, with a written order being approved at the March 2006 Board Meeting. A decision made by the Board on the Request For Approval can be appealed by any party to the Court of Appeals. A Court of Appeal review of the final agency action, could take up to another year, once the appeal has been filed.

The uncertainty associated with the formal adjudicative process based on both Requests For Agency Action, coupled with the appeal of the decision denying standing to the Court of Appeals has required the Sevier Power Company to put on hold the construction of the power plant authorized by the October 12, 2004 Approval Order.

The Sevier Power Company requests the Executive Secretary to hold in abeyance the running of the 18 month period for construction to start from the date that the first Request For Agency Action was filed (November 1, 2004) until the formal adjudication process, including any appeals, is concluded and the review process confirms that the Sevier Power Company has a valid Approval Order. Please advise if further action on the part of Sevier Power Company is necessary in order to obtain the abeyance period requested. If you have any question, please call me at the number mentioned above.

Sincerely,

FINLINSON & FINLINSON, PLLC

Fred W. Finlinson

FWF
cc: The Sevier Power Company

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BEFORE THE UTAH AIR QUALITY BOARD

In the Matter of: Unit 3, Intermountain Power Service Corporation, Millard County, Utah DAQE-AN0327010-04	EXECUTIVE SECRETARY'S MEMORANDUM IN OPPOSITION TO SIERRA CLUB'S MOTION FOR SUMMARY JUDGMENT

Pursuant to Rule 7(c)(1) of the Utah Rules of Civil Procedure, the Executive Secretary of the Utah Air Quality Board ("Executive Secretary") submits this Memorandum in Opposition to Sierra Club's Motion for Summary Judgment dated February 26, 2007. As Sierra Club's motion is premature and the material facts in Sierra Club's motion are disputed, Sierra Club is not entitled to judgment as a matter of law, and the Executive Secretary respectfully submits that the Air Quality Board should deny Sierra Club's Motion for Summary Judgment.

I. INTRODUCTION

On October 15, 2004, the Executive Secretary issued an Approval Order to Intermountain Power Service Company (IPSC) to construct and operate an additional unit at the Intermountain Power Plant in Millard County, Utah. On November 16, 2004, Sierra Club filed a Request for Agency Action ("RFA") to contest the Approval Order. The Executive Secretary anticipates that the Board will hold a hearing on the merits in November 2007. Sierra Club now moves for

summary judgment on the new claim which is the subject of its pending motion to amend, as well as on two claims previously added to its RFA.[1] The Executive Secretary has already filed an opposition to the motion to amend which is now pending before the Board. Sierra Club's Motion for Summary Judgment should be denied because (1) Sierra Club erroneously relies on an inapplicable federal regulation; and (2) Sierra Club's statement of material facts is controverted such that Sierra Club cannot prevail as a matter of law.

Standard of Review

According to Utah Rule of Civil Procedure 56(c), summary judgment should be granted only when it is clear from undisputed facts, viewing evidence in light most favorable to the nonmoving party, that the opposing party cannot prevail. Warren v. Provo City Corp., 838 P.2d 1125, 1128 (Utah 1992); Lach v. Deseret Bank, 746 P.2d 802, 804 (Utah Ct. App. 1987). If there is any dispute as to any issue material to settlement of the controversy, summary judgment should not be granted. Holbrook Co. v. Adams, 542 P.2d 191, 193 (Utah 1975).

Although Sierra Club correctly cites the summary judgment standard under Rule 56, Sierra Club's additional argument that the appellate review standards set forth in Utah Code Ann. § 63-46b-16(4), apply to the Board's review of the Executive Secretary's action is misplaced. The standards in § 63-46b-16(4) only apply to the Utah Court of Appeals when it reviews the Board's decisions. Since Sierra Club seeks not judicial review in an appellate court, but rather contests an "initial order" of the Executive Secretary pursuant to Utah Admin. Code R307-103-3(1) and Utah Code § 63-46b-3(3), said standards do not apply. Rather, in this proceeding the Board sits as an adjudicative body similar to a trial court, evaluating evidence, determining the

[1]On November 15, 2006, Sierra Club amended its Request for Agency Action, adding two new claims.

facts from evidence and witness testimony, and making conclusions of law,[2] with the burden of proof being a preponderance of the evidence.[3]

II. ARGUMENT

A. Sierra Club's Reliance on the Federal Regulation is Misplaced

Sierra Club's proposed new claim (No. 22) alleges that "twenty eight months have passed since the Executive Secretary signed the Approval Order for the proposed plant," and that "the AO is now invalid, having expired automatically on or about April 15, 2006." *See* Sierra Club proposed Second Amended Request for Agency Action at 20-22. In support of summary judgment on this claim, Sierra Club argues that as a matter of law, the Approval Order automatically expired 18 months after issuance. This is a faulty presumption based on a federal regulation that does not apply to this Approval Order. The federal regulation relied upon by Sierra Club, 40 C.F.R. § 52.21(r)(2), states in pertinent part that "[a]pproval to construct shall become invalid if construction is not commenced within 18 months of receipt of such approval . . . ." This regulation was not incorporated into Utah Admin. Code R307-405-19(1) until the

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[2] *See* Utah Code Ann. § 63-46b-8, which governs the procedures for formal adjudicative proceedings. Because Sierra Club has filed a Request for Agency Action to contest an Initial Order of the Executive Secretary, this case is a formal adjudicative proceeding. *See also* § 63-46b-3 (commencement of adjudicative proceedings); Utah Admin. Code R307-103-4 ("[c]ontest of an initial order . . . shall be conducted as a formal proceeding"). By contrast, judicial review by the Court of Appeals or the Supreme Court employs different standards, as outlined in § 63-46b-16. It hardly seems plausible that the Legislature would provide one set of standards to govern adjudicative proceedings before the Air Quality Board and another to govern judicial review by the Court of Appeals if the Legislature intended both to apply the same standards. The bright line between these two standards is not blurred simply because these proceedings are adjudicative in nature.

[3] Walker v. Bd. of Pardons, 803 P.2d 1241 (Utah 1990) (stating that in administrative proceedings, the burden of proof is a preponderance of the evidence).

March 2006 Air Quality Board meeting, to become effective in June 2006.[4] Because this federal regulation was not part of the rules at the time the Executive Secretary issued the Approval Order, the Approval Order is not subject to that regulation.

On the other hand, Condition 8 of the Approval Order and Utah Admin. Code R307-401-18 govern this question, and both endow the Executive Secretary with broad discretion to revoke the Approval Order if construction has not commenced after 18 months.[5] Neither of these provisions mandate an automatic expiration of the approval order.

Consequently, Sierra Club's legal arguments based upon this federal regulation are without merit.

B. The Executive Secretary Disputes Sierra Club's Statement of Undisputed Facts

Rule 7(c)(3)(B) of the Utah Rules of Civil Procedure requires that an opposition memorandum "contain a verbatim restatement of each of the moving party's facts that is controverted" and for each controverted fact, "provide an explanation of the grounds for any dispute . . . ."

In support of its Statement of Facts, Sierra Club attempts to rely upon the preliminary administrative record distributed on February 15, 2007, to show that certain actions did not occur. Because the record is only as broad as the allegations to date in Sierra Club's Request for

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[4] *See* Exhibit A. This exhibit contains the amendments proposed to the Utah Air Quality Board at the March 2006 Air Quality Board meeting. It includes both the original rules and the proposed amendments that were ultimately adopted by the Board.

[5] Utah Admin Code R307-401-18 states that "[a]pproval orders issued by the Executive Secretary in accordance with the provisions of R307-401 will be reviewed 18 months after the date of issuance to determine the status of construction, installation, modification, relocation, or establishment. If a continuous plan of construction, installation, modification, relocation or establishment is not proceeding, the Executive Secretary may revoke the approval order."

Agency Action, there would be no reasonable expectation that the administrative record would contain any documentation concerning a post-permit 18 month review. Consequently, Sierra Club's reliance upon the preliminary administrative record to show what the Executive Secretary may or may not have done in his R307-401-18 review is misplaced.

1. The Executive Secretary Disputes Sierra Club's Fact No. 3 (related to Statement of Reason #22)

The Executive Secretary disputes Sierra Club's Fact No. 3 which states "Eighteen months after the date of the AO - on or about April 15, 2006 - IPSC did not submit the required notification of the status of construction."

The Executive Secretary disputes that "IPSC did not submit the required notification of the status of construction." A review of the relevant time line demonstrates that IPSC submitted notification of the status of the construction. On January 13, 2006, IPSC sent a letter to the Executive Secretary explaining the current status of the IPSC project. *See* IPSC letter to Executive Secretary attached hereto as Exhibit B. In that letter, IPSC outlined its belief that its permit conditions were valid and requested an extension of the 18 month period. This letter provided the Executive Secretary with information regarding the "status of construction, installation, modification, relocation, or establishment" of the IPSC project, and the Executive Secretary elected to not revoke the Approval Order.[6] Whether IPSC submitted the "required" notification is a question of law which the Board would determine by applying the law to the facts. Because Sierra Club has misstated the underlying facts, a genuine issue of material fact still exists, such that Sierra Club is not entitled summary judgment.

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[6] *See* Executive Secretary's letter to IPSC attached hereto as Exhibit C.

2. **The Executive Secretary Disputes Sierra Club's Fact No. 4 (related to Statement of Reason #22)**

Sierra Club's Fact No. 4 states "Eighteen months after the date of the AO – on or about April 15, 2006 – the Executive Secretary made no determination regarding a revocation of the AO, nor whether an extension of the AO was justified."

Again, Sierra Club misstates the facts by relying on a preliminary administrative record which would not be expected to contain information on an 18 month review. *See* section B.1. above. Because a genuine issue of material fact exists on this question, Sierra Club cannot prevail as a matter of law and is not entitled to summary judgment.

3. **The Executive Secretary Disputes Sierra Club's Fact No. 13 (related to Statements of Reasons #20 and #21).**

The Executive Secretary disputes Sierra Club's Fact No. 13 which states that "[o]n August 17, 2006, DAQ responded that if [sic] found 'in accordance with Condition 7 of the Approval Order number DAQE-AN0327010-04, a supercritical PC Boiler is equivalent to the permitted unit,' thereby approving the modification IPSC requested. DAQ did not approve any other changes to the AO."

Sierra Club wrongly labels the Executive Secretary's August 17, 2006 decision to allow IPSC to substitute a supercritical PC boiler for the subcritical PC boiler as a modification of the approval order. "Modification" is defined in Utah Admin. Code R307-101-2 as "any planned change in a source which results in a potential increase in emission." Because use of a supercritical PC Boiler will not cause a process unit change that would increase emissions, there was no modification of the Approval Order. Nor would the substitution qualify as a new source. Because R307-401 by its terms applies only to new sources or modifications that will "increase

the amount of contaminants discharged . . . ." Utah Admin. Code R307-401-3(1), the remaining provisions of R307-401 do not apply. IPP Unit 3 is neither a "new installation" or a "modified installation that will increase the amount of air contaminants discharged." Sierra Club's statement of facts mischaracterizes the Executive Secretary's action and how the law would apply to that action.

Because the Approval Order does not specify the type of boiler that IPSC must use, but rather the emissions limitations that the facility must meet, new modeling and analyses were not required. To be sure, Condition 7 of IPSC's Approval Order specifically allows for equivalency determinations. In making an equivalency determination under Condition 7, the Executive Secretary regulates air pollution, not electricity production. Thus, the relative efficiency of the selected process is not the Executive Secretary's call so long as there is no process unit change that would increase emissions. Therefore, Sierra Club's contention that the two boilers are not equivalent because one may produce more megawatts than the other is an irrelevant distinction. If the substituted process unit does not result in any greater emissions, the two are equivalent for purposes of the Approval Order conditions and the governing law.

Further, the Executive Secretary's decision to allow the substitution satisfies the in-kind replacement provision in Utah Admin Code R307-401-11, which specifically exempts a source from the Notice of Intent requirements of R307-401 when regulatory criteria for replacement in kind are met.

4. <u>The Executive Secretary Disputes Sierra Club's Fact No. 14 (related to Statements of Reasons #20 and #21).</u>

The Executive Secretary disputes Sierra Club's Fact No. 14 which states that

"[t]he Administrative Record contains no analysis to support the Executive Secretary's determination."

This statement of fact by Sierra Club is without basis. Utah Admin. Code R307-401-11(2)(a) requires that the source, before replacing equipment, submit written notification containing a description of the replacement in-kind equipment, including the control capability of any control apparatus and a demonstration that the conditions of R307-401-11(1) are met. The regulation further provides that if the source's submission meets the criteria required by the regulation, the Executive Secretary will update the source's approval order, and "public review under R307-401-7 is not required." Utah Admin. Code R307-401-11(2)(b).

In its request to substitute the supercritical PC boiler, IPSC submitted materials to the Executive Secretary.[7] Based upon the submitted materials and the Division of Air Quality's experience and review of supercritical boilers for the original issuance of the Approval Order, the Executive Secretary agreed that the supercritical PC boiler would be equivalent to the subcritical PC boiler and allowed the substitution. *See* Executive Secretary's letter to IPSC re: Equivalency attached hereto as Exhibit E. The IPSC submissions as well as the Executive Secretary's response thereto are contained in the Administrative Record.

Based on the foregoing, this material fact presented by Sierra Club is disputed. Therefore, Sierra Club is not entitled to summary judgment.

5. <u>The Executive Secretary Disputes Sierra Club's Fact No. 15 (related to Statements of Reasons #20 and #21).</u>

The Executive Secretary disputes Sierra Club's Fact No. 15 which states that "[t]here was

[7] *See* Exhibit D, attached.

no notice to the public of the proposed modification of the AO, and no opportunity for public comment, before the Executive Secretary approved the modification of the AO."

As outlined above, the public notice requirements set forth in Utah Admin. Code R307-401 only apply to new sources or modification that result in an increase in the amounts of contaminants discharged. As neither occurred in this case, the public notice and opportunity for comment provisions therein were not required.

Because there exists a genuine issue of material fact, Sierra Club is not entitled to judgment as a matter of law.

C. Sierra Club's Motion for Summary Judgment is Premature

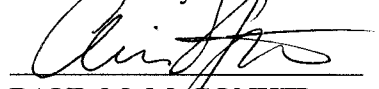
Sierra Club's Motion for Summary Judgment is premature because it is based upon a new claim that is the subject to a pending motion to amend. In the interest of expediency, however, the Executive Secretary responds to the merits of Sierra Club's motion so that it can be heard and resolved at the April board meeting.

CONCLUSION

Based upon the foregoing, Sierra Club is not entitled to summary judgment, and its motion should therefore be denied.

Dated this 19th day of March, 2007.

MARK L. SHURTLEFF
Utah Attorney General



PAUL M. McCONKIE
CHRISTIAN C. STEPHENS
Assistant Attorneys General

CERTIFICATE OF SERVICE

I hereby certify that on the 19th day of March, 2007, a true and correct copy of the foregoing Executive Secretary's Motion for Partial Judgment on the Pleadings was mailed, postage prepaid, and/or emailed to the following:

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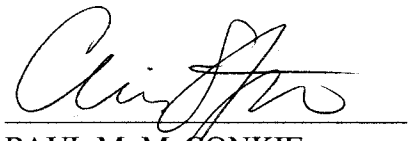

PAUL M. McCONKIE
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EXHIBIT A

State of Utah

Department of Environmental Quality

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Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

Air Quality Board
John M. Veranth, *Chair*
Ernest E. Wessman , *Vice-Chair*
Nan Bunker
Stead Burwell
Jerry D. Grover
James R. Horrocks
Scott Lawson
Dianne R. Nielson
Wayne M. Samuelson
JoAnn B. Seghini
Don Sorensen
Richard W. Sprott,
Executive Secretary

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

DAQ-007-06

UTAH AIR QUALITY BOARD MEETING

Working lunch session will be held prior
12:00-1:00 p.m.

168 North 1950 West (Bldg #2) Room 101

FINAL AGENDA

Wednesday, March 8, 2006
1:30 p.m.

168 North 1950 West (Bldg #2) Room 101

I. Call-to-Order.

II. Date of the Next Air Quality Board Meeting: April 5, 2006.

III. Approval of the Minutes for February's Board Meeting.

IV. Approve Location and Travel for Sevier Power Hearing. Presented By Rick Sprott.

V. Final Adoption: Repeal and Re-enact R307-405, Permits: Major Sources in Attainment or Unclassified Areas (PSD); Amend R307-110-9 and State Implementation Plan Section VIII, Prevention of Significant Deterioration. Presented by Colleen Delaney and Jim Schubach.

VI. Final Adoption: Repeal and Re-enact R307-401, Permits: New and Modified Sources. Presented by Colleen Delaney and Jim Schubach.

VII. Final Adoption: Amend R307-410, Permits: Emission Impact Analysis. Presented by Colleen Delaney and Jim Schubach.

VIII. Propose for Public Comment: Repeal R307-413, Permits: Exemptions and Special Provisions; Amend R307-101-2 Definitions; Amend R307-325, Davis and Salt Lake Counties and Ozone Nonattainment Areas: Ozone Provisions. Presented By Colleen Delaney and Jim Schubach.

IX. Informational Items
A. $PM_{2.5}$ Proposed Standards. Presented by Cheryl Heying.
B. Recent SIP Approvals. Presented By Jan Miller.
C. Compliance. Presented by Jeff Dean.
D. HAPS. Presented by Robert Ford.
E. Monitoring. Presented by Bob Dalley.

In compliance with the American with Disabilities Act, individuals with special needs (including auxiliary communicative aids and services) should contact Charlene Lamph, Office of Human Resources at (801) 536-4413 (TDD 536-4414).

R307. Environmental Quality, Air Quality.
R307-405. Permits: Prevention of Significant Deterioration of Air Quality (PSD).[

]

R307-405-1. Purpose.

This rule implements the federal Prevention of Significant Deterioration (PSD) permitting program for major sources and major modifications in attainment areas and maintenance areas as required by 40 CFR 51.166. This rule does not include the routine maintenance, repair and replacement provisions that were stayed by the DC Circuit Court of Appeals on December 23, 2003, pending appeal. This rule does not include the clean unit and pollution control project provisions that were vacated by the DC Circuit Court of Appeals on June 24, 2005. This rule supplements, but does not replace, the permitting requirements of R307-401.

R307-405-2. Applicability.

(1) Except as provided in (2), the provisions of 40 CFR 52.21(a)(2), effective March 3, 2003, are hereby incorporated by reference.

(2)(a) The provisions in 40 CFR 52.21(a)(2)(iv)(e) are not incorporated by reference.

(b) The last sentence in 40 CFR 52.21(a)(2)(iv)(f) is not incorporated by reference.

(c) The provisions in 40 CFR 52.21(a)(2)(vi) are not incorporated by reference.

(3) Notwithstanding the exemptions in R307-401, any source that is subject to R307-405 is subject to the requirement to obtain an approval order in R307-401-5 through 8.

R307-405-3. Definitions.

(1) Except as provided in (2)below, the definitions contained in 40 CFR 52.21(b), effective March 3, 2003, are hereby incorporated by reference.

(2) "Air Quality Related Values," as used in analyses under 40 CFR 52.21(p) that is incorporated by reference in R307-405-17, means those special attributes of a Class I area, assigned by a federal land manager, that are adversely affected by air quality.

(3)(a)(i) "Major Source Baseline Date" means:

(A) in the case of particulate matter:

(I) for Davis, Salt Lake, Utah and Weber Counties, the date that EPA approves the PM10 maintenance plan that was adopted by the Board on July 6, 2005;

(II) for all other areas of the State, January 6, 1975;

(B) in the case of sulfur dioxide:

(I) for Salt Lake County, the date that EPA approves the sulfur dioxide maintenance plan that was adopted by the Board on January 5, 2005;

(II) for all other areas of the State, January 6, 1975; and

(C) in the case of nitrogen dioxide, February 8, 1988.

(ii) "Minor Source Baseline Date" means the earliest date after the trigger date on which a major stationary source or a major modification subject to 40 CFR 52.21 or R307-405 submits a complete application under the relevant regulations. The trigger date is:

(A) In the case of particulate matter and sulfur dioxide, August 7, 1977, and

(B) in the case of nitrogen dioxide, February 8, 1988.

(iii) The baseline date is established for each pollutant for which increments or other equivalent measures have been established if:

(A) the area in which the proposed source or modification would construct is designated as attainment or unclassifiable under section 107(d)(i)(D) or (E) of the Act for the pollutant on the date of its complete application under 40 CFR 52.21 or R307-405; and

(B) in the case of a major stationary source, the pollutant would be emitted in significant amounts, or, in the case of a major modification, there would be a significant net emissions increase of the pollutant.

(iv) Any minor source baseline date established originally for the TSP increments shall remain in effect and shall apply for purposes of determining the amount of available PM10 increments, except that the executive secretary shall rescind a minor source baseline date where it can be shown, to the satisfaction of the executive secretary, that the emissions increase from the major stationary source, or net emissions increase from the major modification, responsible for triggering that date did not result in a significant amount of PM10 emissions.

(b) In the definition of "baseline area" in 40 CFR 52.21(b)(15)(ii)(b) insert the words "or R307-405" after "Is subject to 40 CFR 52.21".

(c) "Reviewing Authority" means the executive secretary.

(d)(i) The term "Administrator" shall be changed to "executive secretary" throughout R307-405, except as provided in (ii).

(ii) The term "Administrator" shall be changed to "EPA Administrator" in the following incorporated sections:

(A) 40 CFR 52.21(b)(17),

(B) 40 CFR 52.21(b)(37)(i),

(C) 40 CFR 52.21(b)(43),

(D) 40 CFR 52.21(b)(48)(ii)(c),

(E) 40 CFR 52.21(b)(50)(i),

(F) 40 CFR 52.21(l)(2),

(G) 40 CFR 52.21(p)(2), <u>and</u>

(H) [~~the first reference to Administrator in 40 CFR 52.21(y)(4)(i),~~

~~(I) the second reference to Administrator in 40 CFR 52.21(y)(7), and~~

~~(J)~~]40 CFR 51.166(q)(2)(iv).

(e) The definition of "emissions unit" in 40 CFR 52.21(b)(7), effective January 6, 2004, is hereby incorporated by reference.

(f) The definition of "replacement unit" in 40 CFR 52.21(b)(33), effective January 6, 2004, is hereby incorporated by reference.

(g) The following paragraphs that refer to clean units and pollution control projects are not incorporated by reference:

(i) 40 CFR 52.21(b)(2)(iii)(h),

(ii) 40 CFR 52.21(b)(3)(iii)(b),

(iii) 40 CFR 52.21(b)(3)(vi)(d),

(iv) 40 CFR 52.21(b)(32), and

(v) 40 CFR 52.21(b)(42).

([~~3~~]4) "Heat input" means heat input as defined in 40 CFR 52.01(g).

([~~4~~]5) "Title V permit" means any permit or group of permits covering a Part 70 source that is issued, renewed, amended, or revised pursuant to R307-415.

([~~5~~]6) "Title V Operating Permit Program" means R307-415.

([~~6~~]7) The definition of "Good Engineering Practice (GEP) Stack Height" as defined in R307-410 shall apply in this rule.

([~~7~~]8) The definition of "Dispersion Technique" as defined in R307-410 shall apply in this rule.

R307-405-4. Area Designations.

(1) Pursuant to section 162(a) of the federal Clean Air Act, the following areas are designated as mandatory Class I areas:

(a) Arches National Park,

(b) Bryce Canyon National Park,

(c) Canyonlands National Park,

(d) Capitol Reef National Park, and

(e) Zion National Park.

(2) Pursuant to section 162(b) of the federal Clean Air Act, all other areas in Utah are designated as Class II unless designated as nonattainment areas.

(3) No areas in Utah are designated as Class III.

R307-405-5. Area Redesignation.

Any person may petition the Board to change the classification of an area designated under R307-405-4, except for mandatory Class I areas designated under R307-405-4(1).

(1) The petition shall contain a discussion of the reasons for the proposed redesignation, including a satisfactory description and analysis of the health, environmental, economic and social and energy effects of the proposed re[~~s~~]designation.

(2) The petition shall contain a demonstration that the proposed redesignation meets the criteria outlined in Section VIII of the State Implementation Plan and 40 CFR 51.166(e) and (g).

R307-405-6. Ambient Air Increments.

The provisions of 40 CFR 52.21(c), effective March 3, 2003, are hereby incorporated by reference.

R307-405-7. Ambient Air Ceilings.

The provisions of 40 CFR 52.21(d), effective March 3, 2003, are hereby incorporated by reference.

R307-405-8. Exclusions from Increment Consumption.

(1) The following concentrations shall be excluded in determining compliance with a maximum allowable increase:

(a) concentrations attributable to the increase in emissions from stationary sources which have converted from the use of petroleum products, natural gas, or both by reason of an order in effect under section 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) over the emissions from such sources before the effective date of such an order;

(b) concentrations attributable to the increase in emissions from sources which have converted from using natural gas by reason of a natural gas curtailment plan in effect pursuant to the Federal Power Act over the emissions from such sources before the effective date of such plan;

(c) concentrations of particulate matter attributable to the increase in emissions from construction or other temporary emission-related activities of new or modified sources;

(d) the increase in concentrations attributable to new sources outside the United States over the concentrations attributable to existing sources which are included in the baseline concentration; and

(e) concentrations attributable to the temporary increase in emissions of sulfur dioxide, particulate matter, or nitrogen dioxides from stationary sources which are affected by plan revisions approved by the EPA Administrator as meeting the criteria specified in 40 CFR 51.166(f)(4). The temporary increase shall not exceed 2 years in duration unless a longer time is approved by the EPA Administrator. This exclusion is not renewable.

(2) No exclusion of concentration under (1)(a) or (b) above shall apply more than five years after the effective date of the order to which paragraph (1)(a) refers or the plan to which paragraph (1)(b) refers, whichever is applicable. If both such order and plan are applicable, no such exclusion shall apply more than five years after the later of such effective dates.

(3) No exclusion under (1)(e) shall apply to an emission increase from a stationary source which would:

(a) impact a Class I area or an area where an applicable increment is known to be violated; or

(b) cause or contribute to a violation of the national ambient air quality standards.

R307-405-9. Stack Heights.

The provisions of 40 CFR 52.21(h), effective March 3, 2003, are hereby incorporated by reference.

R307-405-10. Exemptions.

(1) The provisions of 40 CFR 52.21(i)(1)(vi) through (viii), effective March 3, 2003, are hereby incorporated by reference.

(2) The provisions of 40 CFR 52.21(i)(2) through (5), effective March 3, 2003, are hereby incorporated by reference.

R307-405-11 Control Technology Review.

The provisions of 40 CFR 52.21(j), effective March 3, 2003, are hereby incorporated by reference.

R307-405-12. Source Impact Analysis.

The provisions of 40 CFR 52.21(k), effective March 3, 2003, are hereby incorporated by reference.

R307-405-13. Air Quality Models.

The provisions of 40 CFR 52.21(l), effective March 3, 2003, are hereby incorporated by reference.

R307-405-14. Air Quality Analysis.

(1) The provisions of 40 CFR 52.21(m)(1)(i) through (iv), (vi), and (viii), effective March 3, 2003, are hereby incorporated by reference.

(2) The provisions of 40 CFR 52.21(m)(2) and (3), effective March 3, 2003, are hereby incorporated by reference.

R307-405-15. Source Information.

The provisions of 40 CFR 52.21(n), effective March 3, 2003, are hereby incorporated by reference.

R307-405-16. Additional Impact Analysis.

The provisions of 40 CFR 52.21(o), effective March 3, 2003, are hereby incorporated by reference.

R307-405-17. Sources Impacting Federal Class I Areas: Additional Requirements.

(1) The provisions of 40 CFR 52.21(p), effective March 3, 2003, are hereby incorporated by reference.

(2) The executive secretary will transmit to the EPA Administrator a copy of each permit application relating to a major stationary source or major modification and provide notice to the EPA Administrator of every action related to the consideration of such permit.

R307-405-18. Public Participation.

(1) Except as provided in (2), the provisions of 40 CFR 51.166(q)(1) and (2), effective March 3, 2003, are hereby incorporated by reference.

(2) The phrase "within a specified time period" in 40 CFR 51.166(q)(1) shall be replaced with the phrase "within 30 days of receipt of the PSD permit application".

R307-405-19. Source Obligation.

(1) Except as provided in (2) below, the provisions of 40 CFR 52.21(r), effective March 3, 2003, are hereby incorporated by reference.

(2)[~~(a)~~] The parenthetical phrase in the first sentence in 40 CFR 52.21(r)(6) shall be changed to read "(other than projects at a source with a PAL)."[

~~(b) The reference to "70.4(b)(3)(viii) of this chapter" in 40 CFR 52.21(r)(7) shall be changed to "R307-415-7i".~~]

R307-405-20. Innovative Control Technology.

(1) Except as provided in (2), the provisions of 40 CFR 52.21(v), effective March 3, 2003, are hereby incorporated by reference.

(2)(a) The reference to "40 CFR 124.10" in 40 CFR 52.21(v)(1) shall be changed to "R307-405-18".

(b) 40 CFR 52.21(v)(2) shall be changed to read "The executive secretary shall, with the consent of the governors of other affected states, determine that the source or modification may employ a system of innovative control technology, if:".

R307-405-21. Actuals PALs.

(1) Except as provided in (3), the provisions of 40 CFR 52.21(aa)(1) through (5) and (7) through (15), effective March 3, 2003, are hereby incorporated by reference.

(2) The provisions of 40 CFR 52.21(aa)(6), effective January 6, 2004, are hereby incorporated by reference.

(3)(a) The reference to "51.165(a)(3)(ii) of this chapter" in 40 CFR 52.21(aa)(4)(ii) shall be changed to "R307-403".

(b) The reference to "51.165(a)(3)(ii) of this chapter" in 40 CFR 52.21(aa)(8)(ii)(2) shall be changed to "R307-403".

(c) The references to "70.6(a)(3)(iii)(B) of this chapter" in 40 CFR 52.21(aa)(14)(ii) shall be changed to "R307-415-6a(3)(c)(ii)".

(d) The date of "March 3, 2003" in 40 CFR 52.21(aa)(15)(i) and (ii) shall be changed to "the effective date of this rule".

R307-405-22. Banking of Emission Offset Credit in PSD Areas.

Banking of emission offset credits in PSD areas will be permitted. To preserve banked emission reductions the executive secretary must identify them in either the Utah SIP or an order. The executive secretary will provide a registry to identify the person, private entity, or government authority that has the right to use or allocate the banked emission reduction and to record any transfer of or lien on these rights.

KEY: air pollution, PSD, Class I area
2006
Notice of Continuation August 11, 2003
19-2-104

R307. Environmental Quality, Air Quality.
R307-405. Permits: Prevention of Significant Deterioration of Air Quality (PSD).
R307-405-1. Definitions.

The following additional definitions apply to R307-405:

"Baseline Area" means any intrastate area (and every part thereof) designated as attainment or unclassifiable under Section 107(d)(1)(D) or (E) of the federal Clean Air Act in which the major source or major modification establishing the minor source baseline date would construct or would have an air quality impact equal to or greater than 1 ug/m3 (annual average) of the pollutant for which the minor source baseline date is established.

(1) Area redesignations under section 107(d)(1) (D) or (E) of the federal Clean Air Act cannot intersect or be smaller than the area of impact of any major stationary source or major modification which:

(a) Establishes a minor source baseline date; or

(b) Is subject to 40 CFR 52.21 or R307-405, and would be constructed in the same state as the state proposing the redesignation.

"Baseline Concentration" means that ambient concentration level which exists in the baseline area at the time of the applicable minor source baseline date.

"Major Modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Clean Air Act.

(1) Any net emissions increase that is significant for volatile organic compounds shall be considered significant for ozone.

(2) A physical change or change in the method of operation shall not include:

(a) routine maintenance, repair, and replacement;

(b) use of an alternative fuel or raw material by reason of an order under section 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation), or by reason of a natural gas curtailment plan pursuant to the Federal Power Act;

(c) use of an alternative fuel by reason of an order or rule under section 125 of the Clean Air Act;

(d) use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;

(e) use of an alternative fuel or raw material by a source which:

(i) the source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any federally enforceable permit condition; or

(ii) the source is approved to use;

(f) an increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition;

(g) any change in ownership at a source

(h) the addition, replacement or use of a pollution control project at an existing electric utility steam generating unit, unless the executive secretary determines that such addition, replacement, or use renders the unit less environmentally beneficial, or except:

(i) when the executive secretary has reason to believe that the pollution control project would result in a significant net increase in representative actual annual emissions of any criteria pollutant over levels used for that source in the most recent air quality impact analysis in the area conducted for the purpose of Title I of the Clean Air Act, if any, and

(ii) the executive secretary determines that the increase will cause or contribute to a violation of any national ambient air quality standard or PSD increment, or visibility limitation.

(i) the installation, operation, cessation, or removal of a temporary clean coal technology demonstration project, provided that the project complies with:

(i) the Utah State Implementation Plan; and

(ii) other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(j) the installation or operation of a permanent clean coal technology demonstration project that constitutes repowering, provided that the project does not result in an increase in the potential to emit of any regulated pollutant emitted by the unit. This exemption shall apply on a pollutant-by-pollutant basis.

(k) the reactivation of a very clean coal-fired electric utility steam generating unit.

"Major Source" means:

(1) any of the following sources of air pollutants which emits, or has the potential to emit, 100 tons per year or more of any pollutant subject to regulation under the Clean Air Act: Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), kraft pulp mills, portland cement plants, primary zinc smelters, iron

and steel mill plants, primary aluminum ore reduction plants, primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries, lime plants, phosphate rock processing plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion plants, sintering plants, secondary metal production plants, chemical process plants, fossil fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants, and charcoal production plants;

(2) any other source which emits, or has the potential to emit, 250 tons per year or more of any air pollutant; or

(3) a source which does not otherwise qualify as a major source as defined in this paragraph, but which is physically changed, which change itself would constitute a major source.

(4) a source which is major for volatile organic compounds is major for ozone.

(5) The fugitive emissions and fugitive dust of a stationary source shall not be included in determining for any of the purposes of this section whether it is a major stationary source, unless the source belongs to one of the following categories of stationary sources:

(a) Coal cleaning plants (with thermal dryers);
(b) Kraft pulp mills;
(c) Portland cement plants;
(d) Primary zinc smelters;
(e) Iron and steel mills;
(f) Primary aluminum ore reduction plants;
(g) Primary copper smelters;
(h) Municipal incinerators capable of charging more than 250 tons of refuse per day;
(i) Hydrofluoric, sulfuric, or nitric acid plants;
(j) Petroleum refineries;
(k) Lime plants;
(l) Phosphate rock processing plants;
(m) Coke oven batteries;
(n) Sulfur recovery plants;
(o) Carbon black plants (furnace process);
(p) Primary lead smelters;
(q) Fuel conversion plants;
(r) Sintering plants;
(s) Secondary metal production plants;

(t) Chemical process plants;

(u) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

(v) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

(w) Taconite ore processing plants;

(x) Glass fiber processing plants;

(y) Charcoal production plants;

(z) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input;

(aa) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Federal Clean Air Act.

R307-405-2. Area Designations.

All areas of the State shall be designated as Class I, II, or III.

(1) Pursuant to section 162(a) of the federal Clean Air Act the following areas are designated as mandatory Class I:

(a) Arches National Park

(b) Bryce Canyon National Park

(c) Canyonlands National Park

(d) Capitol Reef National Park

(e) Zion National Park

(2) Pursuant to section 162(b) of the federal Clean Air Act, all other areas of the State are designated as Class II unless redesignated as provided in R307-405-3 or are designated as nonattainment areas.

R307-405-3. Area Redesignation.

(1) Within the restrictions and requirements of this paragraph, the Board may submit to the Governor for decision a recommendation to redesignate areas from any class to any other class.

(2) In accordance with Section 162(a) of the federal Clean Air Act, areas designated as Class I under R307-405-2 may not be redesignated.

(3) In accordance with Section 164(a) of the federal Clean Air Act, the following areas may be redesignated only as Class I or II.

(a) An area which as of August 7, 1977, exceeded 10,000 acres in size and was a national monument, a national primitive area, a national preserve, a national recreation area, a national wild and scenic river, a national wildlife refuge, a national lakeshore or seashore; and

(b) A national park or national wilderness area established after August 7, 1977, which exceeds 10,000 acres in size.

(4) Except as provided in (2), (3) and (6) the Board may submit to the Governor for decision a recommendation to redesignate areas of the State as Class III if:

(a) There has been compliance with the requirements of (5) below.

(b) Such redesignation will not cause, or contribute to, concentrations of any air pollutant which exceed any maximum allowable increase permitted under the classification of any other area or any national ambient air quality standard; and

(c) Any permit application for any major source or major modification which could receive an approval order only if the area in question were redesignated as Class III, and any material submitted as part of that notice of intent were available, insofar as practicable, prior to any public hearing or redesignation.

In accordance with Section 164 of the federal Clean Air Act, redesignations to Class III may be approved by the Governor only after consultation with appropriate committees of the legislature and if units of local government representing a majority of the residents of the proposed area to be redesignated enact ordinances concurring in the redesignation.

(5) Prior to submittal to the Governor of a recommendation to redesignate any area:

(a) Notice shall be published in each daily newspaper in the affected area and written notice shall be made to local government units, other states, Indian governing bodies, Federal Land Managers whose lands may be affected by the proposed redesignation and public hearings shall be conducted in the affected areas. Such notice shall be made at least 30 days prior to the public hearing and include a statement of the availability of the discussion outlined in (b) below. Prior to the issuance of a notice under this paragraph respecting the redesignation of any Federal lands, a written notice shall be given to the appropriate Federal Land Manager who shall be afforded opportunity (not to exceed 60 days) to confer with the Board respecting the redesignation and to submit written comments and recommendations. In recommending redesignation of any area with respect to which a Federal Land Manager has submitted comments the Board shall publish a list of any inconsistency between such redesignation and such comments and recommendations together with the reasons for recommending

such redesignation against the recommendation of the Federal Land Manager; and

(b) A discussion of the reasons for the proposed redesignation, including a satisfactory description and analysis of the health, environmental, economic and social and energy effects of the proposed redesignation, will be prepared and made available for public inspection at least 30 days prior to the hearing. Any person who petitions the Board for redesignation of an area may be required to prepare and submit this analysis to the Board.

(6) Lands within the exterior boundaries of reservations of federally recognized Indian Tribes may be redesignated only by the appropriate Indian body as provided in Section 164 of the Clean Air Act.

R307-405-4. Increments and Ceilings.

(1) In Class I, II, or III areas, the maximum allowable increases in concentrations of sulfur dioxide, nitrogen dioxide and particulate matter over baseline concentrations of such pollutants are limited to the following:

TABLE

(1)Maximum Allowable Increase (ug/m3)

Pollutant	Class I	Class II	Class III
PM10:			
Annual Arithmetic Mean	4	17	34
24-hr. Maximum	8	30	60
Sulfur Dioxide:			
Annual Arithmetic Mean	2	20	40
24-hr. Maximum	5	91	182
3-hr. Maximum	25	512	700
Nitrogen Dioxide:			
Annual Arithmetic Mean	2.5	25	50

Note (1): At any one location, the maximum allowable increase for other than the annual period may be exceeded once each year. For any period other than the annual period, the applicable maximum allowable increase may be exceeded during one such period per year at any one location.

(2) Variances to Class I areas will be allowed only after compliance with the requirements of and within the increments provided in Section 165 of the federal Clean Air Act, or in the case of PM10 increments, only after compliance with the Title 40 of the Code of Federal Regulations, Section

51.166(p)(4) (as amended-see the June 3, 1993 Federal Register notice, 58 FR 31637) which is hereby incorporated by reference.

(3) In any area, no resultant concentration of any air pollutant shall exceed the concentration permitted under either the national secondary or primary ambient air quality standard whichever concentration is lowest for the pollutant for a period of exposure.

(4) Exclusions from increment consumption. The following concentrations shall be excluded in determining compliance with a maximum allowable increase:

(a) Concentrations attributable to the increase in emissions from sources which have converted from:

(i) the use of petroleum products, natural gas, or both by reason of an order in effect under sections 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974; or

(ii) using natural gas by reason of a natural gas curtailment plan in effect pursuant to the Federal Power Act, over the emissions from such sources before the effective date of such an order or plan.

No exclusion of such concentrations shall apply more than five years after the effective date of the order or the plan. If both an order and plan are applicable, no such exclusion shall apply more than five years after the later of such effective dates.

(b) Concentrations of PM10 attributable to the increase in emissions from construction or other temporary emission-related activities.

(c) Concentrations attributable to the temporary increase in emissions of sulfur dioxide, nitrogen oxides or PM10 from sources which are affected by plan revisions approved by EPA as meeting the criteria specified in 40 CFR 51.166(f)(4).

R307-405-5. Baseline Concentration and Date.

(1) Baseline concentration. A baseline concentration is determined for each pollutant for which a minor source baseline date is established and shall include:

(a) The actual emissions representative of sources in existence on the applicable minor source baseline date except as provided in (2) below;

(b) The allowable emissions of major sources which commence construction before the major source baseline date, but were not in operation by the applicable minor source baseline date.

(2) The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s):

(a) actual emissions from any major source on which construction commenced after the major source baseline date, and

(b) actual emissions increases and decreases at any source occurring after the minor source baseline date.

(3) Baseline date. The minor source baseline date is established for each pollutant for which increments or other equivalent measures have been established if:

(a) the area in which the proposed source or modification would construct is designated as attainment or unclassifiable under section 107(d)(i)(D) or (E) of the federal Clean Air Act for the pollutant on the date of its complete application under 40 CFR 52.21, or R307-405; and

(b) in the case of a major source the pollutant would be emitted in significant amounts, or, in the case of a major modification, there would be a significant net emissions increase of the pollutant. With respect to particulate matter, significant shall mean significant for PM10.

(4)(a) Any minor source baseline date established originally for increments of total suspended particulates shall remain in effect and shall apply for purposes of determining the amount of available PM10 increments, except that the executive secretary may rescind any such minor source baseline date where it can be shown to the executive secretary's satisfaction that the emissions increase from the major stationary source or the net emissions increase from the major modification responsible for triggering that date did not result in a significant amount of PM10 emissions.

(b) Any baseline area established originally for the increments of total suspended particulates shall remain in effect and shall apply for purposes of determining the amount of available PM10 increments, except that such baseline area shall not remain in effect if the executive secretary rescinds the corresponding minor source baseline date in accordance with(a) above.

R307-405-6. PSD Areas - New Sources and Modifications.

(1) Emission Limitations. Any source constructed or modified in a PSD area must meet all applicable emissions requirements of R307 and the Utah State Implementation Plan. A proposed source or modification which is not a major source or major modification may be approved without meeting the requirements in (2) below, provided such source meets all other applicable requirements of these regulations. The

emission limitations shall be stated as conditions of the approval order.

(2) Major Source and Major Modification Review. Every new major source or major modification must be reviewed by the Executive Secretary to determine the air quality impact of the source to include a determination whether the source will cause or contribute to a violation of the maximum allowable increases or the NAAQS in any area. The determination of air quality impact will be made as of the source's projected start-up date. Such determination shall take into account all allowable emissions of approved sources or modifications whether constructed or not, and, to the extent practicable, the cumulative effect on air quality of all sources and growth in the affected area.

(a) In addition to meeting all other requirements of these regulations, any major source or major modification which would be constructed in a PSD area, shall:

(i) Provide the following additional information with the notice of intent required pursuant to R307-401:

(A) An analysis of the air quality impact of the source or modification and a demonstration that allowable emissions increases from the source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), will not cause or contribute to a violation of any maximum allowable increase over the baseline concentration in any area or any NAAQS in any area.

(B) An analysis of ambient air quality in the affected area for each pollutant that a new source would have the potential to emit in a significant amount, and for each pollutant for which a modification would result in a significant net emissions increase. With respect to any such pollutant for which no NAAQS exists, the analysis shall contain such air quality monitoring data as the Executive Secretary determines is necessary to assess ambient air quality for that pollutant in any area that the emissions of that pollutant would affect. With respect to any such pollutant (other than non-methane hydrocarbons) for which such a NAAQS does exist, the analysis shall contain continuous air quality monitoring data gathered for purposes of determining whether emissions of that pollutant would cause or contribute to a violation of the standard or any maximum allowable increase in any area that the emissions of that pollutant would affect. In general, the continuous air quality monitoring data that is required shall have been gathered over a period of at least one year and shall represent at least the year preceding receipt of the notice of intent, except that, if the Executive Secretary determines

that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year (but not to be less than four months), the data that is required shall have been gathered over at least that shorter period. Any data used in the analysis must be gathered using EPA reference methods or equivalent and quality assurance procedures equivalent to 40 CFR Part 58, Appendix B. A monitoring plan will be submitted to the Executive Secretary for approval prior to data collection. The Executive Secretary may grant exceptions or modifications to these monitoring requirements when not inconsistent with federal law.

(C) Upon request of the Executive Secretary, the air quality impact of the source or modification, including meteorological and topographical data necessary to estimate such impact; and the air quality impact of any or all general commercial residential, industrial, and other growth which has occurred since the minor source baseline date in the area the source or modification would affect.

(D) An analysis of the air quality related impact of the source or modification including an analysis of the impairment to visibility, soils, and vegetation and the projected air quality impact from general commercial, residential, industrial, and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.

(ii) After construction of the source or modification, conduct such ambient air quality monitoring as the Executive Secretary determines may be necessary to establish the effect which the emissions from the source or modification may have on the air quality in any area.

(b) If the Executive Secretary finds that the emissions from a proposed major source or major modification would cause a violation of any maximum allowable increase over the baseline concentration in any area, the Executive Secretary shall approve the proposed source if and only if:

(i) the new source or modification is required to meet a more stringent emission limitation sufficient to avoid a violation of the maximum allowable increase and/or

(ii) the new source or modification has acquired sufficient offset to avoid a violation of the maximum allowable increase, and

(iii) the new emission limitations for the proposed source and for any affected existing sources are enforceable.

(c) If the Executive Secretary finds that the emissions from a proposed major source or major modification would

contribute to a known violation of any maximum allowable increase over the baseline concentration in any area, the Executive Secretary shall approve the proposed source if and only if:

(i) the new source or modification has acquired sufficient emission offset so as to provide a positive net air quality benefit in the affected area, and

(ii) any new emission limitations for affected existing sources are enforceable.

(3) The requirements of (2)(a) above shall not apply to a major source or major modification if:

(a) The source is a portable stationary source which has previously received a permit under this paragraph, and

(i) The owner or operator proposes to relocate the source and emissions of the source at the new location would be temporary; and

(ii) The emissions from the source would not exceed its allowable emissions; and

(iii) The emissions from the source would impact no Class I area and no area where an applicable increment is known to be violated;

(b) The source or modification would be a non-profit health or non-profit educational institution and the Board approves a request that it be exempt from those requirements.

(c) The source or modification would be a major source or major modification only if fugitive emission and fugitive dust, to the extent quantifiable, are considered in calculating the potential to emit of the source or modification and the source does not belong to any of the following categories:

(i) Coal cleaning plants (with thermal dryers);

(ii) Kraft pulp mills;

(iii) Portland cement plants;

(iv) Primary zinc smelters;

(v) Iron and steel mills;

(vi) Primary aluminum or reduction plants;

(vii) Primary copper smelters;

(viii) Municipal incinerators capable of charging more than 250 tons of refuse per day;

(ix) Hydrofluoric, sulfuric, or nitric acid plants;

(x) Petroleum refineries;

(xi) Lime plants;

(xii) Phosphate rock processing plants;

(xiii) Coke oven batteries;

(xiv) Sulfur recovery plants;

(xv) Carbon black plants (furnace process);

(xvi) Primary lead smelters;

(xvii) Fuel conversion plants;
(xviii) Sintering plants;
(xix) Secondary metal production plants;
(xx) Chemical process plants;
(xxi) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;
(xxii) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;
(xxiii) Taconite ore processing plants;
(xxiv) Glass fiber processing plants;
(xxv) Charcoal production plants;
(xxvi) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input;
(xxvii) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the federal Clean Air Act.

(d) With respect to a particular pollutant, the allowable emissions of that pollutant from the source, or the net emissions increase of that pollutant from the modification:

(i) would impact no Class I area and no area where an applicable increment is known to be violated, and

(ii) would be temporary.

(4) The requirements of (2)(a) above as they relate to any maximum allowable increase for a Class II area shall not apply to a major modification at a source that was in existence on March 1, 1978, if the net increase in allowable emissions for each pollutant from the modification after the application of best available control technology would be less than 50 tons per year.

(5)(a) The requirements of (2)(a)(i)(A) above pertaining to the impact analysis shall not apply to a source or modification with respect to any maximum allowable increase for nitrogen oxides if the owner or operator of the source or modification submitted a notice of intent before October 15, 1990, and the Executive Secretary subsequently determined that the notice of intent as submitted before that date was complete.

(b) The requirements of (2)(a)(i)(A) above concerning an analysis of the maximum allowable increase over the baseline concentration shall not apply to a stationary source or modification with respect to any maximum allowable increase for PM10 if the owner or operator of the source or modification submitted an application for a permit before December 15, 1994, and the executive secretary subsequently determined that the application as submitted before that date

was complete. Instead, the applicable requirements shall be with respect to the maximum allowable increases for total suspended particulates as in effect on the date the application was submitted. These increments were, for the annual geometric mean: 5, 19, and 37 micrograms/cubic meter for Class I, II and III areas respectively and, for the 24-hour maximum: 10, 37 and 75 micrograms/cubic meter for Class I, II and III areas respectively.

(6) Exemption - Monitoring Requirement

(a) The Executive Secretary may grant exceptions or modifications to the monitoring requirements in (2)(a)(i)(B) above which are not inconsistent with federal law.

(b) The Executive Secretary may exempt a stationary source or modification from the requirements of (2)(a)(i)(B) above with respect to monitoring for a particular pollutant if:

(i) The emissions increase of the pollutant from the new source or the net emissions increase of the pollutant from the modification would cause, in any area, air quality impacts less than the following amounts:

Carbon monoxide - 575 ug/m3, 8-hour average;
Nitrogen dioxide - 14 ug/m3, annual average;
PM10 - 10 micrograms/cubic meter, 24-hour average;
Sulfur dioxide - 13 ug/m3, 24-hour average;
Lead - 0.1 ug/m3, 24-hour average;
Mercury - 0.25 ug/m3, 24-hour average;
Beryllium - 0.0005 ug/m3, 24-hour average;
Ozone - No de minimis air quality level is provided for ozone. However, any proposed source or modification subject to PSD with net increase of 100 tons per year or more of volatile organic compounds subject to PSD would be required to perform an ambient impact analysis including the gathering of ambient air quality data;
Fluorides - 0.25 ug/m3, 24-hour average;
Vinyl chlorides - 15 ug/m3, 24-hour average;
Total reduced sulfur - 10 ug/m3, 1-hour average;
Hydrogen sulfide - 0.04 ug/m3, 1-hour average;
Reduced sulfur compounds - 10 ug/m3, 1-hour average; or

(ii) The concentrations of the pollutant in the area that the source or modification would affect are less than the concentrations listed or the pollutant is not listed in (i) above.

R307-405-7. Increment Violations.

Where the Board determines that an increment under R307-405-4 is violated, the Board shall promulgate a plan and implement regulations to eliminate the violation.

R307-405-8. Banking of Emission Offset Credit in PSD Areas.

Banking of emission offset credits in PSD areas will be permitted. To preserve banked emission reductions the Executive Secretary must identify them in either the Utah SIP or an order and shall provide a registry to identify the person, private entity, or government authority that has the right to use or allocate the banked emission reduction and to record any transfer of or lien on these rights.

KEY: air pollution, PSD, Class I area
July 12, 2001
Notice of Continuation August 11, 2003
19-2-104

EXHIBIT B

Intermountain Power Agency

January 13, 2006

Rick Sprott
Executive Secretary
Utah Division of Air Quality
150 North 1950 West
Salt Lake City, UT 84116

Re: IPA Unit 3 Request for 24 Month Extension

Dear Mr. Sprott:

The Intermountain Power Service Company ("IPSC") submits this request for a twenty-four (24) month extension of the period within which to commence construction under Approval Order #DAQE-AN0327010-04. The AO was issued by the Utah Department of Air Quality ("UDAQ") on October 15, 2004 for the addition of a new Unit 3 at the Intermountain Power Generating Station. The request will extend the time period to commence construction from April 15, 2006 until April 15, 2008.

Construction Status

General Condition #8 of the AO indicates that IPSC shall notify you in writing on the status of construction and/or installation of Unit 3 within 18 months of the issuance of the AO. The development participants have been actively engaged in many project development activities at great expense, including the following:

- developing joint ownership arrangements
- preparing agreements to govern the use of facilities in common with units 1 and 2
- preparing a joint operating agreement covering units 1, 2 and 3
- exploring fuel supply strategies
- initiating engineering and other technical work prerequisite to the procurement of equipment.

The development participants have spent in excess of $5 million dollars in preparatory work for the Unit 3 project and will continue to vigorously pursue these ongoing activities leading to the selection of an owner's engineer, preparation of

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detailed specifications for construction, and procurement of necessary equipment and on-site construction activities commencing before April 15, 2008.

Extension Requests

Extension requests for major coal plants and other complex facilities are not uncommon. The Wyoming DEQ recently granted a 24 month extension to the Two Elks project and the North Dakota Department of Health granted a 36 month extension for a North Dakota PSD permit. Other states have granted extensions as well.

AO Timing

It is, quite literally, not possible to complete all of the tasks necessary to develop, design and construct a coal-fired power plant of this size in the 18 month window prescribed in the AO. For that reason, AO General Condition #8 and the underlying requirements contemplate a process to extend the AO as necessary.

In addition to the amount of time required to complete the development tasks noted above, there are long lead times for many construction-related activities and significant timing needs associated with the financial complexities surrounding a project with construction costs of over $1 Billion-a complicated 950 MW Unit 3 project with unique features, i.e. engineering designs, financing, and ownership. In addition, the legal challenge to AO and the subsequent appeal of the Air Board's decision has taken a tremendous amount of time and resources. Until that legal challenge is completed, the AO does not have the certainty necessary to make final construction plans and finalize financing.

Discussions among the development participants likewise require large amounts of time, along with the time to complete the resource planning requirements of individual development participants (including the SB 26 mandated PSC approval process for PacifiCorp). For all of these reasons, IPSC believes that adequate justification exists to extend the 18 month timeframe to commence construction for an added 24 months. The need is even greater because one of the original development participants unexpectedly withdrew from the project—the Los Angeles Department of Water & Power (LADWP). This in and of

itself caused significant delay and is an added reason why an extension is necessary.

BACT Update

IPSC and the development participants are mindful of the need to assure that there have not been any significant changes in Best Available Control Technology ("BACT") determinations since the AO for Unit 3 originally was issued. In that regard, a study by CH2MHill has gathered BACT determinations for facilities similar to the new Unit 3 at the Intermountain Power Generating Station, issued since October 15, 2004. See Attachment A for a list of the BACT determinations updated since October 15, 2004. This study reveals that no new pollution control technologies have been determined as BACT for facilities similar to Unit 3. Based on this review, IPSC has determined that no new technologies or emissions levels have been established as BACT that would require any revisions to the AO.

Accordingly, IPSC respectfully requests that a twenty-four (24) month extension be granted to allow IPSC sufficient time to further develop, design and begin construction on the new Unit 3. Thank you for your attention to this matter, and please contact me with any questions.

Sincerely,

Reed T. Searle

Reed T. Searle
General Manager

Enclosures
Cc: Doug Hunter, UAMPS
Ernie Wessman, PacifiCorp

Attachment A

The Approval Order for IPP Unit 3 was issued on October 15, 2004. Since that issuance, some new air quality construction permits have been issued for pulverized coal fired utility boilers. Enclosed is an updated listing of these permits similar to the one that was included in the appendix of the original Notice of Intent for IPP 3.

The permits that were issued subsequent to October 15, 2004 and were reviewed are Comanche Unit 3, Weston Unit 4, WYGEN Unit 2, Newmont Unit 1, as well as the re-issuance of the Bull Mountain Roundup Units 1 and 2 permit.

CH2M HILL has reviewed these permits and has determined that for NOx, all of these permits are in the range of 0.07 to 0.08 pounds per million BTU 30 day rolling average. The IPP AO is 0.07 pounds per million BTU 30 day rolling average. Therefore there is no justification to revise the IPP NOx limit.

For SO_2, all of these permits are in the range of 0.09 to 0.10 pounds per million BTU 30 day rolling average. The IPP AO is 0.09 pounds per million BTU 30 day rolling average and 0.10 24 hour average. Therefore there is no justification to revise the IPP SO2 limit.

For CO the permits range from 0.13 to 0.15 pounds per million BTU with the Comanche permit at 0.13 pounds per million BTU eight hour rolling average during normal operation but a much higher limit of 0.30 pounds per million BTU during startup. The Newmont permit is for a shorter averaging time (24 hour rolling average) while the IPP AO CO limit is for 30 day rolling average of 0.15 pounds per million BTU. The IPP AO is well in the range of the most recent permits and therefore we see no reason to revise the IPP CO limit.

For VOC, the permits range from 0.0027 to 0.01 pounds per million BTU. The Newmont permit is for 8.1 pounds per hour which is equivalent to 0.004 pounds per million BTU at full load. The IPP AO is 0.0027 pounds per million BTU which is the lowest BACT limit. Therefore we see no reason to revise the IPP VOC limit.

For PM_{10}, the permits range from 0.012 to 0.18 pounds PM_{10} filterable per million BTU. The IPP AO is at 0.012 pounds per million BTU for a three test run average. This is the lowest BACT limit of all the permits and therefore we see no reason to revise the IPP PM_{10} limit.

For H_2SO_4, the permits range from .001 to 0.005 pounds per million BTU. The IPP AO limits H_2SO_4 emissions to .0044 pounds per million BTU 24 hour block average. The Newmont limit is 0.001 pounds per million BTU (2.04 pounds per hour) using a dry lime FGD system while IPP Unit 3 will use a wet limestone scrubber. Given this difference in sulfur control technology the Newmont permit limit for H_2SO_4 is inapplicable. The remaining permits range from 0.0042 to .005 and the IPP is in this range. Therefore we see no reason to revise the IPP H_2SO_4 limit.

TABLE E-1
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for CO
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Proper Boiler Design and Operat	not given	0.15	lb/MMBTU		12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Combustion Control	not given	0.15	lb/MMBtu		7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Combustion Control	not given	0.13	lb/MMBtu	8-hour Rolling avg.	7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Good Combustion Controls	not given	0.15	lb/MMBTU	24-hour	5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Combustion Control	not given	0.15 3,399	lb/MMBTU tons/yr	1-Day 12-month Rolling avg.	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	Combustion Control	not given	0.15 3,000	lb/MMBTU lbs/hr	30-day Rolling avg. 8-hour Block avg.	10/15/2004

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:
- RBLC Determinations added during or after October 15, 2004
- SIC Code: 4911
- Process Type Code: 11.100 - Coal Combustion

TABLE E-2
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for VOC
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Proper Boiler Design and Operation	not given	0.003	lb/MMBtu		12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Combustion Control	not given	0.01	lb/MMBtu		7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Combustion Control	not given	0.0036	lb/MMBtu		7/5/2005
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Combustion Control	not given	0.0036 81.6	lb/MMBTU tons/yr	1-Day 12-month Rolling avg.	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr		not given	0.0027	lb/MMBTU	3 stack test run average	10/15/2004

Notes:

TABLE E-3
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for PM
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Fabric Filter	not given	0.012	lb/MMBTU	24-hour	5/05/2005 No. AP4911-1349

Notes:

TABLE E-4
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for PM_{10}
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Fabric Filter Baghouse	not given	0.012	lb/MMBTU		12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Fabric Filter	not given	0.012	lb/MMBtu		7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Fabric Filter	not given	0.012 0.020	lb/MMBtu	3-hour Rolling avg (filterable) 3-hour Rolling avg (filterable & condensable)	7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Fabric Filter	not given	0.012	lb/MMBTU	24-hour	5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Fabric Filter	not given	0.018	lb/MMBTU	3-hour Rolling avg.	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	Fabric Filer	not given	0.012 221	lb/MMBTU lbs/hr	3 stack test run avg. 24-hour Block avg	10/15/2004

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:

TABLE E-5
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for Lead
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit	Averaging Period	Permit Date and Permit No.

Notes:

TABLE E-6
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for Fluorides
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit	Averaging Period	Permit Date and Permit No.
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant	1	Coal Fired Boiler 2030 MMBTU/HR	Dry Spray Scrubber and Fabric Filter	not given	1.17 lbs/hr		5/05/2005 No. AP4911-1349

Notes:

TABLE E-7
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for SO_2
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Dry Flue Gas Desulfurization System	90%	0.15	lb/MMBtu	1-hour	12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Dry Lime FGD	not given	0.10 0.12	lb/MMBTU lb/MMBTU	30-day Rolling avg. 3-hour Block avg.	7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Dry Lime FGD	not given	0.1	lb/MMBtu	30-day Rolling	7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Lime Spray Dryer Scrubber	not given	0.09 0.065	lb/MMBTU lb/MMBTU	24-hour (Coal S >= 0.45%) - 95% removal eff, 30-day period 24-hour (Coal S <0.45%) - 91% removal eff, 30-day period	5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Dry Lime FGD	not given	0.10 0.09	lb/MMBTU lb/MMBTU	24-hour Block avg. 30-day Rolling avg.	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	Wet Limstone FGD	not given	0.10 0.09	lb/MMBTU lb/MMBTU	24-hour Block avg. 30-day Rolling avg.	10/15/2004

Notes:

TABLE E-8
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for NO_x
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit			Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	SCR, Low NOx Burners, and Overfire Air	not given	0.1	lb/MBtu		1-hour	12/08/2005 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	SCR and Low NOx Burners	not given	0.07	lb/MBtu		30-day Rolling	7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	SCR and Low NOx Burners	not given	0.08	lb/MBtu		30-day Rolling	7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	SCR, Low NOx Burners, and Overfire Air	not given	0.067	lb/MBtu		24-hour rolling	5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	SCR and Low NOx Burners	not given	0.07	lb/MBtu		30-day Rolling	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	SCR and Low NOx Burners	not given	0.07	lb/MBtu		24-hour	10/15/2004

Notes:

TABLE E-9
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for H_2SO_4
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit		Averaging Period	Permit Date and Permit No.
	Roundup Power Roundup Power Project Montana	2	Coal Fired Boiler 390 MW each	Dry Flue Gas Desulfurization System	not given	0.0064	lb/MMBTU		12/08/05 3182-01
	Black Hills WYGEN Unit 2 Wyoming	1	Coal Fired Boiler 100 MW	Dry Lime FGD	not given	No Limit			7/11/2005
	Xcel Comanche Unit 3 Colorado	1	Coal Fired Boiler 7,421 MMBtu/hr	Dry Lime FGD	not given	0.0042	lb/MMBtu		7/5/2005
NV-0036	Newmont Nevada Energy Investment, Inc. TS Power Plant Nevada	1	Coal Fired Boiler 2030 MMBTU/HR	Dry Spray Scrubber and Fabric Filter	not given	2.06	lbs/hr		5/05/2005 No. AP4911-1349
	Wisconsin Public Power Plant Unit 4 Wisconsin	1	Coal Fired Boiler 5,173 MMBtu/hr	Dry Lime FGD	not given	0.005	lb/MMBTU	24-hour	10/18/2004
	Intermoutain Power Project Unit 3 Utah	1	Coal Fired Boiler 9050 MMBtu/hr	Wet Limestone FGD	not given	0.0044	lb/MMBTU	24-hour Block avg	10/15/2004

Notes:

TABLE E-10
NSR RACT/BACT/LAER Clearinghouse Database
BACT-PSD Sources for Beryllium
Coal Fired PC Boilers

RBLC ID	Company Name and Location	# of Units	Unit and Size	Control Technology	Control Efficiency	Emission Limit	Averaging Period	Permit Date and Permit No.

Notes:
NSR RACT/BACT/LAER Clearinghouse database (http://www.epa.gov/ttn/catc) was queried for the following:
- RBLC Determinations added during or after January 1995
- SIC Code: 4911
- Process Type Code: 11.110 - Coal Combustion

The State
of Wyoming

Dave Freudenthal, Governor

Department of Environmental Quality

Herschler Building • 122 West 25th Street • Cheyenne, Wyoming 82002

ADMIN/OUTREACH	ABANDONED MINES	AIR QUALITY	INDUSTRIAL SITING	LAND QUALITY	SOLID & HAZ. WASTE	WATER QUALITY
(307) 777-7758	(307) 777-6145	(307) 777-7391	(307) 777-7368	(307) 777-7756	(307) 777-7752	(307) 777-7781
FAX 777-3610	FAX 777-6462	FAX 777-5616	FAX 777-6937	FAX 777-5884	FAX 777-5973	FAX 777-5973

May 17, 2004

Mr. Fred Carl
Director Environmental Services
Black Hills Corporation
P.O. Box 1400
Rapid City, SD 57709

Re: Air Quality Permit CT-3030 Extension

Dear Mr. Carl:

The Division is in receipt of your letter dated March 25, 2004, requesting to extend the construction period for Air Quality Permit CT-3030. Permit CT-3030, issued September 25, 2002, authorized the construction of a 500 megawatt (MW) pulverized coal fired electric generating facility, known as WYGEN 2, located at 13151 Hwy 51 approximately five (5) miles east of Gillette in Campbell County, Wyoming.

Condition 6 of the issued permit states that construction shall commence within 24 months of issuance of the permit. The allotted 24 months for construction is scheduled to lapse on September 25, 2004. An appeal of the final permit was filed on November 25, 2002 and action on the appeal is pending. For this reason, the Division will extend the permit for a period of one year. Construction must commence prior to September 25, 2005, for the approval to construct the WYGEN 2 Electric Generating Plant to remain valid.

If you should have any questions concerning this matter, please contact this office at (307) 777-7391.

Sincerely,

Dan Olson
Administrator
Air Quality Division

cc: Bob Gill
Mike Warren
Main File CT-3030

EXHIBIT C

State of Utah

Department of
Environmental Quality

Dianne R. Nielson, Ph.D.
Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

FILE COPY

DAQE-GN0327010-06

January 27, 2006

Reed Searle
Intermountain Power Agency
10653 South River Front Parkway, Suite 120
South Jordan, Utah 84095

Re: Review of the Approval Order DAQE-AN0327010-04 dated October 15, 2004.

Dear Mr. Searle:

The Utah Division of Air Quality (UDAQ) has received your letter dated January 13, 2006 in accordance with Approval Order number DAQE-AN0327010-04.

UDAQ reviewed your AO in accordance with the R307-401-11 of the Utah Administrative Code (UAC) and prepared the attached Memo.

Please note that Executive Secretary will not exercise the right to revoke the above referenced AO as outlined in R307-401-11. However, by April 15, of 2008, IPSC shall again notify the Executive Secretary in writing on the status of the construction and/or installation. At that time the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11, UAC.

Sincerely,

Richard W. Sprott, Executive Secretary
Utah Air Quality Board

RWS: MR:kw
Attachment: GN0327010A-06

State of Utah

Department of Environmental Quality

Dianne R. Nielson, Ph.D.
Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

FILE COPY

DAQE-GN0327010A-06

MEMORANDUM

TO: Intermountain Power Service Corporation (IPSC) Project Source File (Site ID 10327)

THROUGH: Richard W. Sprott, Executive Secretary
Regg Olsen, Permitting Branch Manager RDO 1/24/06
Rusty Ruby, NSR Section Manager, R 1/24/06

FROM: Milka Radulovic, NSR Engineer

SUBJECT: Review of the Approval Order (AO) for IPSC Unit #3 number DAQE-AN0327010-04 in Accordance with Condition 8 and Utah Administrative Code (UAC) Rule 307-401-11

DATE: January 23, 2006

We reviewed the IPSC letter dated January 13, 2006, sent to UDAQ in accordance with AO Condition 8. Reviewing the letter UDAQ finds that IPSC is engaged in many project development activities at substantial expense in excess of 5 million dollars.

UDAQ also finds that on November 12, 2004, IPSC petitioned the Utah Air Quality Board for review of Condition 24 in the AO dated October 15, 2004. Settlement negotiations took place between UDAQ and IPSC, resulting in a Joint Stipulation. The Joint Stipulation was approved by the Order of the Air Quality Board on September 7, 2005. The AO incorporates the terms of the Joint Stipulation. In addition, on November 15, 2004, Western Resources Advocates appealed the AO and action on the appeal is pending. These actions caused significant delay and necessitated an extension of the construction program.

For these reasons the Executive Secretary will not exercise the right to revoke the above referenced AO as outlined in R307-401-11. However, by April 15, of 2008, IPSC shall again notify the Executive Secretary in writing on the status of the construction and/or installation. At that time the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11, UAC.

EXHIBIT D

UAMPS
UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS
2825 E. Cottonwood Parkway
Suite 200
Salt Lake City, Utah 84121-7077
Phone: 801-566-3938
Toll Free: 800-872-5961
Fax: 801-561-2687

N0327-016

UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY
AUG - 7 2006
DIVISION OF AIR QUALITY

August 4, 2006

Mr. Rick Sprott
Utah Division of Air Quality
150 North 1950 West
Salt Lake City, Utah 84114

Re: Engineering and Procurement of IPSC Unit 3 Boiler-Supercritical

Dear Mr. Sprott:

We are writing concerning our intent to use a supercritical boiler design for the Intermountain Power Service Corporation (IPSC) Unit # 3 to be located near Delta, Utah. The IPSC Unit 3 Development Committee is preparing bids for the engineering and procurement phase of construction. This letter is part of our efforts to keep the Division apprised of our construction status. As you recall, in December 2002, IPSC submitted a Notice of Intent (NOI) to permit and construct this nominal 950-gross megawatt (MW) (900-net MW) pulverized coal (PC) fired unit. An Approval Order (AO) for the construction of the proposed project was issued by the Utah Division of Air Quality (UDAQ) on October 15, 2004. The AO does not specify the specific type of PC-boiler the facility must use.

As we have proceeded with the highly complex process of developing the plant, we have concluded that a supercritical boiler design is more efficient and better for the environment, that it reflects the latest engineering and market developments for PC facilities, and that it accommodates those who favored a supercritical boiler design in their comments regarding the AO. We believe that use of a supercritical boiler design is consistent with the AO. We are preparing to order this equipment, and want to notify you prior to entering into an Engineering, Procurement and Construction (EPC) contract. We do not believe that any update of the AO is necessary in response to this notification letter. The following information is submitted to explain our conclusion that a supercritical design is consistent with the AO.

What is the difference between a Subcritical and Supercritical Boiler Design?

A supercritical boiler is functionally equivalent to a subcritical boiler except that, in order to create greater efficiencies, a supercritical boiler generates steam at higher pressures and

temperatures. This makes supercritical boiler-turbine technology more efficient in converting heat from the burning coal to driving the steam turbine generator. In all other respects, a supercritical boiler is equivalent to a subcritical design.

In a typical fossil-fuel boiler, water-containing tubes line the inside of the furnace walls. Fuel is ignited and burned as it enters the furnace. The burning fuel releases thermal energy, which is absorbed by the water in the tubes. As the temperature of the water rises, the water begins to boil. Water and steam are separated in a boiler drum and the steam, after additional heating in the boiler, is piped from the boiler to the steam turbine.

In a supercritical boiler design, the operating pressure exceeds the critical point of water. The critical point of water is at a pressure of 3,208 pounds per square inch absolute (psia); a point above which distinct liquid and vapor (steam) phases no longer exist, and the water is in a supercritical fluid state. Water and steam separation occurs without a boiler drum and the superheated fluid is sent directly to the steam turbine. A plant operating at this high pressure is more energy efficient and is referred to as a supercritical unit. Other than the higher operating pressure and temperature of steam at the supercritical plant, the design features are equivalent to a subcritical unit.

The subcritical boiler design has a 2520 psig/1050°F/1050°F steam power cycle providing a net plant efficiency (HHV)1 of approximately 35.77 percent, while the supercritical boiler design typically has a 3500 psig/1050°F/1100°F steam power cycle providing a net plant efficiency (HHV) of approximately 36.75 percent. As a result, there is approximately a three percent improvement in heat rate between the two cycles, thereby increasing the power output of the steam turbine-generator for the same coal burned in the boiler. Alternatively, a supercritical boiler can produce the same level of power output using a lesser amount of coal.

Using a supercritical boiler will not increase the heat input rate or the emission limits included in the AO. It will not increase coal consumption limits or alter the fuel types. The supercritical boiler will have the same maximum gross heat input of 9,050 million British Thermal Units per hour (MMbtu/hr), as listed in the AO. No changes will occur to the stack parameters. The stack will be designed with the same exit velocity and temperature as modeled. Therefore no additional dispersion modeling should be required since the emissions are the same and the stack parameters will not change.

---

[1] Net Plant Efficiency (HHV) is defined as the net electrical output of the plant divided by the higher heating value fuel consumption of the plant.

Will emissions remain stable or decrease with a supercritical boiler design?

Unit emissions, coal feed rate and heat input to the boiler will in all cases remain at or below the levels specified in the AO. See Exhibit 1 for a comparison of the sub critical design and supercritical boiler design.

Installation of a supercritical boiler will result in a net decrease in emissions as measured in lbs/MWh. Also, as with the subcritical boiler design, the supercritical boiler will use a baghouse for particulate emissions control, a wet limestone scrubber for control of sulfur dioxide and acid gas emissions; and Low NOx Burners/Over-Fire-Air and Selective Catalytic Reduction for NOx emissions control. The design of the emissions control equipment will be the same as for the subcritical design.

Are BACT-Level Emission Controls the same for Supercritical and Subcritical Boilers?

The BACT analysis completed for IPP3 showed that BACT-Level emission controls were the same for both designs. The same list of potential control technologies were considered for each pollutant in the BACT analyses for supercritical units as was used in the IPSC Unit 3 PC BACT analysis. The control effectiveness of the technologies for each pollutant was also the same. No distinction was made between the supercritical PC boiler design of these units and the subcritical PC design of other units when consulting the EPA's RACT/BACT/LAER Clearinghouse (RBLC) and recently approved PSD permits to assist in selecting BACT for the projects. The primary difference between the BACT analysis outcomes for the various units was that a wet limestone FGD process was selected for IPSC Unit 3 with an emission limit of 0.09 Lb/MMBtu on a 30 day rolling average based on burning western bituminous coal versus some of the other units which each selected a dry lime FGD process with an emission limit of 0.10 Lb/MMBtu based on burning subbituminous Powder River Basin (PRB) coal. Low-NOx burners with Selective Catalytic Reduction were selected as BACT for NOx control and fabric filters were selected as BACT for Particulate Matter (PM) control.

The BACT process evaluates pollution control equipment in order to determine a proper BACT emission rate; it does not evaluate the boiler design. UDEQ (and EPA) have repeatedly confirmed this. Whether the boiler is subcritical or supercritical design, the BACT process evaluates the same pollution control equipment. The results of the IPP3 BACT analysis showed that there is no difference in pollution control equipment or BACT emission limits between a subcritical and a supercritical boiler.

Is it necessary to update the existing AO?

We believe it is not necessary to update the AO. When UDAQ issued its AO, DAQE-AN0327010-04, for the new IPSC Unit 3 on October 15, 2004, the AO approved installation of a "Dry-bottom Pulverized Coal Fired Boiler for base load operation with Overfire Air Ports

System" or its equivalent (the NOI described the unit as "an indoor type, subcritical, PC-fired boiler designed for base load operation" and then the AO imposed permit conditions to limit emissions). See AO at Condition #7. The AO does not specify the type of boiler as subcritical or supercritical. The AO only species the maximum heat input rate, 9050 x 106 Btu/hr, and the coal consumption limits, 3,541,248 tons of coal burned per rolling 12-month period. See AO Condition #7 and Condition #14. In addition, the AO limits the fuel to either "bituminous or blend of bituminous and up to thirty percent subbituminous coals." See AO at Condition #19. Selection of a supercritical boiler will not affect or exceed the heat input rate, the consumption limits or the types of fuel specified in the AO. Selection of a supercritical boiler does not constitute a major modification because it does not constitute a physical change or change in operation of an existing source and does not result in a significant emissions increase. Indeed, as noted, the emission limits will be the same for a subcritical or supercritical design. Selection of a supercritical boiler will not affect or exceed the heat input rate, the consumption limits or the types of fuel specified in the AO. In fact, the supercritical boiler will have the same coal consumption rate and the same gross heat input rate allowed in the AO, but it will be more efficient. Accordingly, a supercritical boiler design is consistent with the AO, and was the preferred boiler design of some commentrs during the public comment process for the AO. Therefore, the use of a supercritical boiler is consistent with the AO. This letter is notification to you of our continuing construction efforts, and in the near future the IPSC Unit 3 Development Committee intends to enter into an EPC contract for a supercritical boiler.

If you have any questions or need additional information, please contact me at your earliest convenience. Thank you for your consideration of this matter.

Sincerely,

Douglas O. Hunter
Chairman, Unit 3 Development Committee

Enclosure

Exhibit 1
IPP Unit 3 Project
Unit 3 Boiler Emissions Comparison

	Permit Basis Subcritical Design	Super Critical Boiler Design
Coal Feed Rate (tons/hr)	404	404
Heat Input to Boiler (MMBtu/hr)	9,050	9,050
Annual Capacity Factor (%/yr)	100	100
NOx		
NOx Boiler Emissions (lb/MMBtu)	0.35	0.35
NOx Stack Emissions (lb/MMBtu)	0.070	0.070
SO_2		
SO_2 Boiler Emissions (lb/MMBtu)	1.34	1.34
SO_2 Stack Emissions (lb/MMBtu)	0.090	0.090
CO		
CO Emission Factor (lb/MMBtu)	0.154	0.154
Filterable PM		
Filterable PM Stack Emissions (lb/MMBtu)	0.013	0.013
Filterable PM_{10}		
Filterable PM_{10} Stack Emissions (lb/MMBtu)	0.012	0.012
VOC		
VOC Emissions (lb/MMBtu)	0.00268	0.00268
Sulfuric Acid Mist		
H_2SO_4 Stack Emissions (lb/MMBtu)	0.00439	0.00439
Ammonium Sulfate		
$(NH_4)_2SO_4$ Stack Emissions (lb/MMBtu)	0.00030	0.00030
Hydrogen Chloride		
HCl Stack Emissions (lb/MMBtu)	0.00421	0.00421
HCl Stack Emissions (lb/hr)	38.13000	38.13000
Hydrogen Fluoride		
HF Stack Emissions (lb/MMBtu)	0.001	0.001
Stack Conditions		
Stack Exit Flow (acfm)	3,244,126	3,244,126
Stack Exit Diameter (feet)	31.85	31.85
Stack Exit Temperature (degF)	135	135

EXHIBIT E

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

State of Utah

Department of
Environmental Quality

Dianne R. Nielson, Ph.D.
Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

DAQE-GN0327016-06

August 17, 2006

Project fee ID:N0327-016

Doug Hunter
Chairman, Unit 3 Development Committee
2825 E. Cottonwood Parkway
Salt Lake City, Utah 84121-7077

Dear Mr. Hunter

Re: Equivalency Determination for the Intermountain Power Service Corporation (IPSC) Unit 3 Pulverized Coal (PC) Fired Boiler

This letter is in response to the letter submitted August 7, 2006, concerning the installation of the IPSC Unit 3 PC boiler at the Intermountain Power Plant, near Delta, Utah . Utah Division of Air Quality agrees, that in accordance with Condition 7 of the Approval Order number DAQE-AN0327010-04*, a supercritical PC boiler is equivalent to the permitted unit.

The supercritical boiler shall operate under the conditions listed in Approval Order number DAQE-AN0327010-04*.

Please direct any technical questions you may have on this letter to Ms. Milka Radulovic. She may be reached at (801) 536-4232.

Sincerely,

Richard W. Sprott, Executive Secretary
Utah Air Quality Board

RWS:MR:kw

Fred W. Finlinson (1078)
Finlinson & Finlinson, PLLC
11955 Lehi-Fairfield Road
Saratoga Springs, UT 84043
Telephone: 801-554-0765
Facsimile: 801-766-8717

Brian W. Burnett (3772)
Callister Nebeker & McCullough
10 East South Temple, Suite 900
Salt Lake City, UT 84133
Telephone: 801-530-7428
Facsimile: 801-364-9127

Attorneys for Sevier Power Company

BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – the Sevier Power Company 270 MW Coal-Fired Power Plant, Sevier County Project Code: N2529-001 DAQE-AN2529001-04	**SEVIER POWER COMPANY'S MOTION FOR PARTIAL JUDGMENT ON THE PLEADINGS**

Pursuant to Utah Rules of Civil Procedure, Rule 12(c), Sevier Power Company ("Sevier Power") hereby files this Motion for Partial Judgment on the Pleadings regarding the Sierra Club's Request for Agency Action relating to the following issues in the Approval Order issued to Sevier Power by the Executive Secretary of the Utah Division of Air Quality on October 12, 2004:

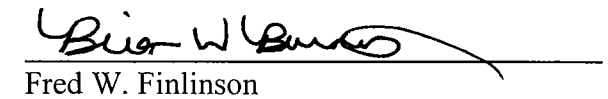
1. UDAQ acted appropriately by not addressing carbon dioxide and other greenhouse gases relating to the Sevier Power facility.

2. UDAQ acted appropriately by not considering Integrated Gasification Combined Cycle process in its BACT determination for Sevier Power facility.

The issues raised by the Sierra Club were not and are not properly before the Utah Division of Air Quality, and the Board of Air Quality should dismiss the Sierra Club's Request for Agency Action relating to those issues as more fully set forth in Sevier Power Company's Memorandum in Support of Motion For Partial Judgment on the Pleadings attached hereto and incorporated by reference herein.

RESPECTFULLY SUBMITTED this 26th day of February, 2007.

FINLINSON & FINLINSON, PLLC
CALLISTER NEBEKER & McCULLOUGH



Fred W. Finlinson
Brian W. Burnett
Attorneys for Sevier Power Company

CERTIFICATE OF SERVICE

I hereby certify that on February 26th, 2007, the undersigned served a copy of the foregoing **SEVIER POWER COMPANY'S MOTION FOR PARTIAL JUDGMENT ON THE PLEADINGS** on the following by:

Joro Walker
David H. Becker
Western Resource Advocates
425 East 100 South
Salt Lake City, Utah 84111
jwalker@westernresources.org
dbecker@westernresources.org

VIA EMAIL

Rick Sprott, Executive Director
Cheryl Heying, Acting Executive Director
Division of Air Quality
150 North 1950 West
Salt Lake City, Utah 84116
rsprott@utah.gov

VIA EMAIL

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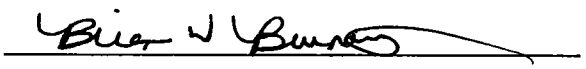

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Attorneys for Sevier Power Company

BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – the Sevier Power Company 270 MW Coal-Fired Power Plant, Sevier County Project Code: N2529-001 DAQE-AN2529001-04	**SEVIER POWER COMPANY'S MEMORANDUM IN SUPPORT OF MOTION FOR PARTIAL JUDGMENT ON THE PLEADINGS**

Sevier Power Company ("Sevier Power") hereby files this Memorandum in Support of its Motion for Partial Judgment on the Pleadings regarding the Utah Chapter of the Sierra Club's ("Sierra Club") Request for Agency Action filed before the Utah Board of Air Quality ("Board"). On October 12, 2004, the Executive Secretary of the Board issued an Approval Order ("AO") to Sevier Power for a power plant to be constructed in Sevier County, Utah. On November 12, 2004, the Sierra Club filed a Request for Agency Action asking the Board to reconsider certain issues in the AO because the Sierra Club felt that the issues were not adequately addressed by the Executive Secretary and the Utah Division of Air Quality

(collectively "UDAQ") in its review of the AO including: (1) Whether UDAQ acted appropriately by not addressing carbon dioxide and other greenhouse gases relating to the Sevier Power facility, and (2) Whether UDAQ acted appropriately by not considering Integrated Gasification Combined Cycle ("IGCC") process in its BACT determination for Sevier Power facility,

Sevier Power respectfully requests that the Board dismiss the Sierra Club's request relating to those issues because those matters were not and are not appropriately before UDAQ as more fully described below.

PROCEDURE

Sevier Power has filed a Motion for Partial Judgment on the Pleadings pursuant to Rule 12(c) of the Utah Rules of Civil Procedure. Rule 12(c) is a tool that can be used to resolve legal issues in a proceeding rather than issues that are related to factual disputes. The legal issues in question here involve whether the law requires regulation of carbon dioxide and other greenhouse gases and whether IGCC must be part of a Best Available Control Technology ("BACT") review of the Sevier Power AO. The purpose of Sevier Power's Motion is not to discuss if the Board should regulate greenhouse gases or if IGCC is economical or effective. Those issues should be addressed through laws or regulations, not in Sevier Power's AO.

In addition, the actions of the UDAQ are presumed to be correct and valid. See Cottonwood Heights Citizens Association v. Board of Commissioners of Salt Lake County, 593 P.2d 138, 140 (Utah 1979).

ARGUMENT

1. UDAQ acted appropriately by not addressing carbon dioxide and other greenhouse gases relating to the Sevier Power facility.

(a) The federal Clean Air Act, 42 U.S.C.A. 7401 et seq., is the foundation of the laws which govern the regulation of air pollutants in the United States.

The Clean Air Act sets forth the process whereby air pollutants are regulated through the promulgation of regulations. Sevier Power's AO is subject to the following Federal Limitations and Requirements:

> 21. In addition to the requirements of this AO, all applicable provisions of 40 CFR 60, New Source Performance Standards (NSPS) Subpart A, 40 CFR 60.18 and Subpart Da, 40 CFR 60.40a to 60.49a (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) and Subpart Y 40 CFR 60.250 to 60.254 (Standards of Performance for Coal Preparation Plants) apply to this installation.
>
> 22. In addition to the requirements of this AO, all applicable provisions of 40 CFR 72, 73, 75, 76, 77 and 78 – Federal regulations for the Acid Rain Program under Clean Air Act Title IV apply to this installation.

(b) No federal standards regarding carbon dioxide and greenhouse gases have been promulgated by federal agencies.

There are no federal regulations which require Utah to regulate carbon dioxide or greenhouse gases.

> At this time there are no regulations or standards prohibiting, limiting or controlling the emissions of greenhouse gases from stationary sources. Carbon dioxide is not considered a regulated air pollutant for permitting purposes.

In re: Kawaihae Congregation Project, 1997 WL 221391, 7 E.A.D. 107 (E.P.A 1997).

In Massachusetts v. EPA, 415 F.3d 50 (D.C. Cir. 2005), the United States Court of Appeals, District of Columbia, upheld EPA's denial of a petition asking it to regulate carbon dioxide and other greenhouse gases from new motor vehicles on the basis that EPA did not have statutory authority to regulate greenhouse emissions from motor vehicles and even if it did, it would not exercise the authority at this time. Although this decision, which is being appealed to the U.S. Supreme Court, pertains to motor vehicles, the federal statutory and regulatory frame work is similar to the circumstances in the Sevier Power AO. There are no federal regulations pertaining to carbon dioxide or greenhouse gases.

(c) Utah's does not regulate air pollutants regarding carbon dioxide and greenhouse gases.

In addition to implementing the Clean Air Act, Utah has the Utah Air Conservation Act, Utah Code Ann. § 19-2-104(1)(a) which provides that the Board may make rules "regarding the control, abatement, and prevention of air pollution."

The Board has not made rules for the regulation of carbon dioxide or greenhouse gases, either while the Sevier Power application was pending, when the AO was issued or even subsequent up to and including the date of this Motion. The proper forum to establish this "greenhouse" rule is not in this matter, but more appropriately in the commencement of rulemaking under the Utah Administrative Rulemaking Act, Utah Code Ann. § 63-46a-12. Since there is no regulation regarding carbon dioxide or greenhouse gases, the UDAQ's issuance of the AO was proper and in full compliance with the provisions, rules and practices of the UDAQ.

(d) Utah may not implement a more stringent standard than federal regulations without rulemaking.

19-2-106 Rulemaking authority and procedure.

(1) Except as provided in Subsection (2), no rule which the board makes for the purpose of administering a program under the federal Clean Air Act may be more stringent than the corresponding federal regulations which address the same circumstances. In making rules, the board may incorporate by reference corresponding federal regulations.

(2) The board may make rules more stringent than corresponding federal regulations for the purpose described in Subsection (1), only if it makes a written finding after public comment and hearing and based on evidence in the record, that corresponding federal regulations are not adequate to protect public health and the environment of the state. Those findings shall be accompanied by an opinion referring to and evaluating the public health and environmental information and studies contained in the record which form the basis for the board's conclusion.

Utah Code Ann. § 19-2-106 (emphasis added).

Utah has not taken the steps required by statute to establish regulations for carbon dioxide and greenhouse gases including:

(i) public comment

(ii) public hearing

(iii) evidence

(iv) written findings based upon evidence in the record that federal regulations are not adequate to protect public health and the environment.

For the Board to accept the Sierra Club's position and find that the AO is inadequate regarding carbon dioxide and greenhouse gases would be de facto rulemaking without having gone through the requirements set forth in Utah Code Ann. § 19-2-06 which

prohibits a more stringent Utah standard than the federal standard unless the procedure set forth above has been followed. If the Sierra Club wishes to have UDAQ address carbon dioxide and greenhouse gases, it should petition UDAQ to initiate a rulemaking proceeding as allowed by Utah Administrative Rulemaking Act, Utah Code Ann. § 63-46a-12.

(e) Best Available Control Technology ("BACT") does not require UDAQ to regulate carbon dioxide and greenhouse gases as alleged by the Sierra Club.

The definition of BACT as set forth in Utah Admin. Code R307-101-2 is as follows:

> "Best Available Control Technology (BACT)" means an emission limitation and/or other controls to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree or reduction of each pollutant subject to regulation under the Clean Air Act and/or the Utah Air Conservation Act emitted from or which results from any emitting installation, which the Air Quality Board, on a case-by-case basis taking into account energy, environmental and economic impacts and other costs, determines is achievable for such installation through application of production processes and available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall applications of BACT result in emissions of any pollutants which will exceed the emissions allowed by Section 111 or 112 of the Clean Air Act.

Utah Admin. Code R307-101-2 (emphasis added).

The Sierra Club alleges that UDAQ is "required to consider other environmental impacts, such as greenhouse gas emissions when determining BACT for a facility". The Sierra Club omits an important segment of the BACT definition which requires a BACT review for each "pollutant subject to regulation under the Clean Air Act and/or the Utah Air Conservation Act". Since carbon dioxide and greenhouse gases are not subject to regulation under the Clean

Air Act and/or the Utah Air Conservation Act, no BACT review is necessary for the Sevier Power AO.

The Sierra Club's Request for Agency Action should be dismissed by the Board because there is no legal foundation for UDAQ to regulate carbon dioxide or greenhouse gases.

2. UDAQ acted appropriately by not considering Integrated Gasification Combined Cycle process in its BACT determination for Sevier Power facility.

Sevier Power proposed to build a CFB coal-fired power plant. The UDAQ did not require IGCC as part of the BACT for the Sevier Power plant. This decision is consistent with applicable laws and regulations. The Sierra Club has requested that the Sevier Power AO be declared illegal, should be rescinded and/or remanded to UDAQ for proper BACT analysis.

(a) Clean Air Act – BACT Requirement

The Clean Air Act provides that:

> "No major emitting facility ... may be constructed in any area to which this part applies unless ... the facility is subject to the best available control technology for each pollutant subject to regulation under this chapter emitted from, or which results from, such facility."

Clean Air Act, 42 U.S.C.A. § 7475(a)(4).

(b) Utah – BACT Definition

Utah defines BACT as follows:

> "Best Available Control Technology (BACT)" means an emission limitation and/or other controls to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree or reduction of each pollutant subject to regulation under the Clean Air Act and/or the Utah Air Conservation Act emitted from or which results from any emitting installation, which the Air Quality Board, on a case-by-case basis taking into account energy, environmental and economic impacts

> and other costs, determines is achievable for such installation through application of production processes and available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant....

Utah Admin. Code R307-101-2.

(c) Sevier Power's AO Received a BACT Analysis

UDAQ utilized a BACT analysis when reviewing Sevier Power's Notice of Intent ("NOI") application. The AO states as follows:

> This project is a new major Prevention of Significant Deterioration (PSD) source. Onsite meteorological monitoring, air dispersion modeling, air quality impacts analysis including visibility and PSD class I and II impacts analysis, and a complete top-down Best Available Control Technology (BACT) review were completed and submitted as part of the NOI.

AO at Page 1.

UDAQ made a BACT determination regarding the CFB coal-fired power plant set forth in Sevier Power's AO. The Sierra Club's complaint is that the BACT analysis did not mandate the review of IGCC technology for the Sevier Power AO.

Sevier Power provided a review of IGCC for information purposes to UDAQ. Since the review was not required, there was no corresponding requirement for public comment. Sevier Power is not proposing to build a coal gasification plant.

(d) BACT – Not a Means to Redefine the Source

The BACT process may not be used to force an applicant to redefine the design of the source of the project. The long established practice of EPA is as follows:

> Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives. For example, applicants proposing

> to construct a coal-fired electric generator, have not been required by EPA as part of the BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product ...

EPA's New Source Review Workshop Manual.

There are no Utah laws or regulations which require consideration of IGCC in a BACT analysis. UDAQ properly concluded that BACT does not require a CFB facility to redesign its process to become an IGCC project. IGCC is a variation on a natural gas combines cycle plant in which coal derived gas (produced by coal gasification) replaces natural gas. To impose IGCC on the Sevier Power project redefines the design of the source which is not the practice of EPA or Utah.

(e) Utah may not implement a more stringent standard than federal regulations without rulemaking.

As discussed more fully above, the Board may not establish any rule under administration of the Clean Air Act which is more stringent than the corresponding federal regulations without going through the rulemaking process. The Sierra Club's request that the Board impose an IGCC review in a BACT process creates a more stringent Utah regulation than federal regulations. Utah has not taken the steps required by statute to establish regulations relating to IGCC which include public comment, public hearing, evidence and written findings based upon evidence in the record that federal regulations are not adequate to protect public health and the environment. See Utah Code Ann. § 19-2-106.

The Sierra Club's Request for Agency Action should be dismissed by the Board because there is no legal requirement to include an IGCC analysis as part of the BACT review of Sevier Power's AO.

CONCLUSION

Based upon the foregoing, Sevier Power respectfully requests that the Board dismiss the Sierra Club's Request for Agency Action relating to the two issues set forth above.

RESPECTFULLY SUBMITTED this 26th day of February, 2007.

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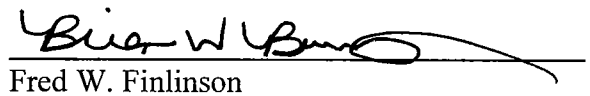

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CERTIFICATE OF SERVICE

I hereby certify that on February 26th, 2007, undersigned served a copy of the foregoing **SEVIER POWER COMPANY'S MEMORANDUM IN SUPPORT OF MOTION FOR PARTIAL JUDGMENT ON THE PLEADINGS** on the following by:

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BEFORE THE UTAH AIR QUALITY BOARD

In the Matter of: Sevier Power Company Power Plant Sevier County, Utah DAQE-AN2529001-04	EXECUTIVE SECRETARY'S MOTION FOR JUDGMENT ON THE PLEADINGS

Pursuant to Rule 12(c) of the Utah Rules of Civil Procedure, the Executive Secretary of the Utah Air Quality Board ("Executive Secretary") submits this Motion for Judgment on the Pleadings in Support of Motion for Judgment on the Pleadings pertaining to the Request for Agency Action filed by Sierra Club.

This motion is supported by the memorandum in support filed with this motion and all other pleadings on file with the Board in this action.

Dated this 26th day of February, 2007.

MARK L. SHURTLEFF
Utah Attorney General

Paul M. McConkie, Assistant Attorney General
Christian C. Stephens, Assistant Attorney General

CERTIFICATE OF SERVICE

I hereby certify that on this 26th day of February, 2007, I caused a copy of the foregoing to be mailed by United States Mail, postage prepaid, and/or emailed to the following:

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BEFORE THE UTAH AIR QUALITY BOARD

In the Matter of: Sevier Power Company Power Plant Sevier County, Utah DAQE-AN2529001-04	EXECUTIVE SECRETARY'S MEMORANDUM IN SUPPORT OF MOTION FOR PARTIAL JUDGMENT ON THE PLEADINGS

Pursuant to Rule 12(c) of the Utah Rules of Civil Procedure, the Executive Secretary of the Utah Air Quality Board ("Executive Secretary") submits this Memorandum in Support of its Motion for Partial Judgment on the Pleadings pertaining to Sierra Club's Request for Agency Action (the "RFA").

At issue in this proceeding is whether the Executive Secretary conducted the proper regulatory review in issuing an Approval Order (AO) to Sevier Power Company (SPC) to construct and operate a coal-fired power plant in Sevier County, Utah. As the Executive Secretary will show, no genuine issues of material fact remain on the claims addressed in the motion, and consequently the Executive Secretary is entitled to judgment as a matter of law. Accordingly, the Executive Secretary respectfully submits that the accompanying motion for partial judgment on the pleadings should be granted.

INTRODUCTION

On October 12, 2004, the Executive Secretary issued an Approval Order to Sevier Power Company to construct and operate a coal-fired power plant in Sevier County, Utah. On November 12, 2004, Sierra Club filed a Request for Agency Action ("RFA") appealing the

Approval Order. A hearing on the merits is set for September 2007. For purposes of limiting the evidentiary hearing to those claims where there exists a genuine issue of material fact, the Executive Secretary submits this memorandum in support of its motion for partial judgment on the pleadings.

STANDARD OF REVIEW

The Utah Rules of Civil Procedure allow a defendant to file a Motion for Judgment on the Pleadings pursuant to Rule 12(c) as follows:

> After the pleadings are closed but within such time as not to delay the trial, any party may move for judgment on the pleadings. If, on a motion for judgment on the pleadings, matters outside the pleadings are presented to and not excluded by the court, the motion shall be treated as one for summary judgment and disposed of as provided in Rule 56,and all parties shall be given reasonable opportunity to present all material made pertinent to such a motion by Rule 56.

A Rule 12(c) motion will be governed by the same standard as a Rule 12(b)(6) motion to dismiss, Seolas v. Bilzerian, 951 F. Supp. 978, 980 (D. Utah 1997) and the moving party must "clearly establish that no material issue of fact remains to be resolved and that he is entitled to judgment as a matter of law." 5C Wright & Miller, Federal Practice and Procedure § 1368 (2005).

The Board has a two-fold responsibility at a hearing on the merits: (1) to determine the facts and (2) to apply the law to those facts. Judgment on the pleadings is a procedural device which allows the Board to resolve claims "when moving party is entitled to judgment on the face of the pleadings themselves." Mountain America Credit Union v. McClellan, 854 P.2d 590, 591 (Utah Ct. App. 1993). Judgment on the pleadings is appropriate when neither party disputes the material facts underlying their dispute. Town of Mapleton v. Kelly, 17 P. 52 (Utah 1911) (stating that presence of material facts prevents entry of judgment on the pleadings). "A 'material fact' is one which affects the rights or liabilities of the parties." Holland v. Iron Mining Co., 293 P.2d 700, 709 (Utah 1956). In other words, a material fact is one that must be

determined by a fact finder at a hearing because the parties do not agree on the basic factual circumstances that have resulted in their dispute. Conversely, no issue of material fact exists when the parties agree as to the facts. If the Board grants this motion, the evidentiary hearing will be limited to claims where a factual dispute remains to be resolved.

STATEMENT OF UNDISPUTED FACTS

1. On April 1, 2003, Sevier Power Company submitted a Prevention of Significant Deterioration (PSD) permit application and its Notice of Intent (NOI) to construct a 270 megawatt (MW) circulating fluidized bed (CFB) coal-fired power plant near Sigurd, Utah.

2. PSD applies to new major sources or major modifications at existing sources located in areas designated as in attainment or as unclassifiable with the National Ambient Air Quality Standards (NAAQS). It requires the following:

- application of the "Best Available Control Technology" (BACT);
- an air quality analysis;
- an additional impacts analysis; and
- public involvement.

3. The proposed Sevier Power Company facility is considered a new major source for the pollutants carbon monoxide (CO), nitrogen oxides (NOx), sulfur dioxide (SO_2) and particulate matter (PM).

4. The area where the facility proposes to locate is designated as having attainment status for all pollutants.

5. Integrated Gasification Combined Cycle (IGCC) is a method of producing electricity by gasifying coal, removing pollutants before combustion, and then burning the syngas in a modified combined cycle gas-fired power plant. IGCC is not a control technology but rather a separate process from the proposed CFB technology.

6. The Executive Secretary did not require the applicant to include IGCC as part of its BACT analysis.

7. The Executive Secretary did not require regulation of carbon dioxide (CO_2) or other greenhouse gas emissions from the proposed unit.

8. A public comment period was held in accordance with Utah Admin. Code R307-401-4 and comments were received.

9. On October 12, 2004, Richard W. Sprott, Executive Secretary of the Utah Air Quality Board signed an Approval Order authorizing construction and operation of the proposed Sevier Power Company 270 mega-watt circulating fluidized bed (CFB) coal-fired power plant.

ARGUMENT

This motion addresses the following two claims made by Sierra Club: (1) that the UDAQ was required to but failed to regulate carbon dioxide and other greenhouse gases; and (2) that the UDAQ was required to but failed to consider IGCC as part of the BACT analysis.

1. No Genuine Issue of Material Fact Exists on Either Claim.

Both of Sierra Club's claims are ripe for judgment on the pleadings because no genuine issue of material fact exists on either claim. That is, there is no dispute as to whether the Executive Secretary regulated greenhouse gases, nor is there a dispute as to whether he required that IGCC be considered as part of the BACT analysis. Both parties agree that he did not. The only point of dispute is whether on these two claims, the Executive Secretary properly applied the Board's rules.

2. State Law Sets Forth Stringency Requirements on the Board's Rulemaking Authority

Both claims share common underlying principles for points of reference. First, Utah law provides the Board with authority to make rules and a procedure for making those rules. Pursuant to statute and rule, the Air Quality Board and the Board's Executive Secretary administer the New Source Review program under authority delegated under the federal Clean

Air Act (CAA) and under approval and oversight of the United States Environmental Protection Agency (EPA). The United States Supreme Court in Alaska v. EPA, 540 U.S. 461(2004) recognized that "Congress [ ] vested EPA with explicit and sweeping authority to enforce CAA requirements relating to the construction and modification of sources under the PSD program, including BACT" while noting at the same time "the need [by the EPA] to accord appropriate deference to States' BACT designations." See Alaska, at 490.

The Utah Air Conservation Act, § 19-2-104(1)(a), authorizes the Board to make rules "regarding the control, abatement, and prevention of air pollution." Per § 19-2-107(2)(g), the Executive Secretary may enforce those rules. However, Utah law limits the Board's rulemaking authority. Utah Code Ann. § 19-2-106 limits the Board's authority to make rules that are more stringent than the existing federal regulations:

> (1) Except as provided in Subsection (2), no rule which the board makes for the purpose of administering a program under the federal Clean Air Act may be more stringent than the corresponding federal regulations which address the same circumstances. In making rules, the board may incorporate by reference corresponding federal regulations.
>
> (2) The board may make rules more stringent than corresponding federal regulations for the purpose described in Subsection (1), only if it makes a written finding after public comment and hearing and based on evidence in the record, that corresponding federal regulations are not adequate to protect public health and the environment of the state. Those findings shall be accompanied by an opinion referring to and evaluating the public health and environmental information and studies contained in the record which form the basis for the board's conclusion

Thus, unless the Board follows the requirements of § 19-2-106(2), the Board cannot make rules more stringent than the corresponding federal regulations addressing the same circumstances.

In the two claims that are at issue here, Sierra Club cites Utah's rule regarding Best Available Control Technology, or BACT. Under the Prevention of Significant Deterioration (PSD) program requirements, a prospective facility must employ the "best available control technology" for each regulated pollutant emitted. 42 U.S.C. § 7475(a)(4); Utah Admin. Code

R307-401-6(1). Utah Admin. Code R307-101-2(4) defines Best Available Control Technology as:

> an *emission limitation* and/or other *controls* to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree or reduction of each pollutant subject to regulation under the Clean Air Act and/or the Utah Air Conservation Act *emitted from or which results from any emitting installation*, which the Air Quality Board, on a case-by-case basis taking into account energy, environmental and economic impacts and other costs, determines is achievable for *such installation* through application of production processes and available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques *for control* of each such pollutant. In no event shall applications of BACT result in emissions of any pollutants which will exceed the emissions allowed by Section 111 or 112 of the Clean Air Act.

Id. (emphasis added).

Therefore, BACT is an "emission limitation" to control emissions from an "emitting installation" that the Executive Secretary "determines is achievable for such installation."

Id. Utah's BACT rule essentially mirrors the federal BACT rule.[1]

3. The Executive Secretary Regulates Pollutants Based on Rules Promulgated by the Air Quality Board

Sierra Club Claim No. 1: UDAQ failed to address carbon dioxide and other greenhouse gases.

In this claim, Sierra Club makes the single factual allegation that the Executive Secretary did not require regulation of greenhouse gases. The Executive Secretary does not dispute this allegation and acknowledges that he did not require regulation of greenhouse gases. Thus, there is no genuine issue of material fact.

[1] The federal BACT definition is found in 42 U.S.C. 7479(3) and provides in pertinent part: "The term best available technology means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, no a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant . . . ."

Although Sierra Club claims that both the Clean Air Act and the Utah Air Conservation Act require regulation of greenhouse gases, in its RFA Sierra Club provides no authority from either of those two acts to support its allegation. Neither the Clean Air Act nor the Utah Air Conservation Act lists greenhouse gases as regulated pollutants or contains any other requirement to regulate greenhouse gases. Regulation of greenhouse gases would require rulemaking by the Board, which has not occurred. Because the Board has not made any rules requiring the regulation of greenhouse gases, the Executive Secretary had no rule to enforce, and thus was correct as a matter of law in not requiring regulation of greenhouse gases in the SPC Approval Order.

4. BACT Rule Applies to Regulated Pollutants

Further, Sierra Club's reliance on the BACT rule is misplaced and out of context. A full reading of the entire BACT rule shows that the "environmental impacts" considered during a BACT analysis apply to ". . . *each pollutant subject to regulation* under the Clean Air Act and/or the Utah Air Conservation Act . . . ." Utah Code Ann. R307-101-2(4) (emphasis added). Therefore, the BACT rule governs only pollutants that are already regulated, and the Executive Secretary was not allowed to consider any theoretical environmental impacts of greenhouse gases during the BACT analysis.

5. EPA Agrees with Executive Secretary on Regulating Greenhouse Gases

The Executive Secretary's position on this issue is consistent with that of the EPA, which has likewise deemed that it (EPA) has no authority under the Clean Air Act to regulate greenhouse gases. For instance, in an April 28, 1997 decision, the EPA's Environmental Appeals Board denied review of a PSD permit issued by the Hawaii Department of Health. See In re Kawaihae Cogeneration Project, 7 E.A.D. 107 (EAB 1997). In that appeal, the petitioners claimed that the Hawaii Department of Health improperly ignored greenhouse gases in its permit decision. Id. The Department

responded that "there are no regulations or standards prohibiting, limiting or controlling the emissions of greenhouse gases from stationary sources [in that] carbon dioxide is not considered a regulated air pollutant for permitting purposes." Id.

Then, in 1999, various groups petitioned EPA to initiate rulemaking to regulate greenhouse gases and EPA denied the petition on the basis that EPA has no authority to regulate greenhouse gases. See Control of Emissions from New Highway Vehicles and Engines, 68 Fed. Reg. 52,922 (denial of petition Sept. 8, 2003). Although various parties appealed the denial, the District of Columbia Court of Appeals upheld EPA's decision. See Commonwealth of Massachusetts v. EPA, 415 F.3d 50, 58 (D.C. Cir. 2005).

Based on the foregoing, the parties have no factual dispute, and thus there is no genuine issue of material fact. Accordingly, the Executive Secretary is entitled to judgment on this claim as a matter of law.

6. Sierra Club's IGCC Claim is Purely a Question of Law

Sierra Club Claim No. 2: UDAQ Failed to Consider Adequately Integrated Gasification Combined Cycle (IGCC) in its BACT Determination and Failed to Require the Production Process for IPP Unit 3.

In its RFA, Sierra Club takes the position that "UDAQ is required to evaluate this technology comprehensively as part of its BACT analysis" and that "consideration of [this] process design is a necessary part of its BACT analysis." Sierra Club RFA at 4. The narrowness of this claim presents only two potential questions of material fact: (1) whether IGCC is a separate process which would redefine the design of the source; and (2) whether the Executive Secretary required consideration of IGCC during the BACT stage of the permitting process. "Redefining the source" is a term of art used by the EPA in its New Source Review Workshop Manual ("NSR Manual") which means to substitute one design process for an entirely different design process. The NSR Manual provides a concrete (and very similar to the situation here) example when it states that

sources are not generally required to redefine the scope of their proposed facilities as part of the BACT analysis: "applicants proposing to construct a coal-fired electric generator would not be required as part of the BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity)." NSR Manual at B.13.

Sierra Club states in its RFA that it considers IGCC to be a "production process" and "*a method of producing electricity* by gasifying coal, removing pollutants – including greenhouse gases – before combustion, and then burning the 'clean' syngas in *a modified combined cycle gas-fired power plant*." Sierra Club RFA at 3 (emphasis added). The Executive Secretary concurs with this definition of the IGCC process. Because the Executive Secretary and the Sierra Club agree (1) on what IGCC is; and (2) that the Executive Secretary did not require its consideration, there remains no genuine issue of material fact. This claim, therefore, is purely a legal question of what the BACT rule requires.

The position taken by Sierra Club in its RFA that the BACT rule requires the Executive Secretary to require the applicant to consider IGCC in its BACT analysis makes this a very narrow issue of law for the Board to rule on because it takes any discretion away from the Executive Secretary. Sierra Club's position is contrary to not only the plain reading of the rule, but is also contrary to Utah law, EPA guidance, and to what regulatory authorities in most states to consider the issue have required.

7. Sierra Club's Position on IGCC Claim is Contrary to Plain Reading of the BACT Rule

Applying a plain reading to the BACT rule, BACT is an "emission limitation" to control emissions from an "emitting installation" that the Executive Secretary "determines is achievable for such installation . . . ." Utah Admin. Code R307-101-2(4). Utah Admin. Code R307-101-2 defines an installation as "a discrete process with identifiable emissions which may be part of a

larger industrial plant. The BACT rule goes on to state that determining what is achievable "for such installation" includes "application of production processes and available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques". Utah Admin. Code R307-101-2(4). By definition, the BACT analysis includes control technologies that can be applied to an installation that has already been identified. Otherwise, there is no emitting installation for which control technology can be analyzed.

On the other hand, Sierra Club's interpretation conflicts with both the definition of BACT as an "emission limitation" for the proposed installation, and the definition of installation, which states that an installation is a "discrete process with identifiable emissions." Utah Admin. Code R307-101-2.

8. In Applying BACT Rule, Executive Secretary Follows EPA Guidance

Because Utah's BACT rule essentially mirrors the federal BACT rule, and because of the restrictions on the Board's rulemaking authority (as it relates to equivalent federal rules), the Executive Secretary looks to the EPA's NSR Manual for guidance in administering Utah's New Source Review program. For the BACT analysis, the UDAQ employs EPA's recommended "top down" methodology. The United States Supreme Court has quoted at length from the NSR Manual, in describing the top-down method:

> . . . . the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent-or 'top'-alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not 'achievable' in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

Alaska Dept. of Envtl. Conservation v. EPA, 540 U.S. 461, 475-76 (2004) (hereinafter "ADEC") (quoting EPA's New Source Review Workshop Manual at B.2 (Draft Oct. 1990)).

To reiterate from paragraph 6 above, the NSR Manual also states that "production processes" or "available methods, systems and techniques" for pollutant reduction that would "redefine the design of the source" are not required to be included in the BACT analysis:

> [h]istorically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives. For example, applicants proposing to construct a coal-fired electric generator have not been required by EPA as part of a BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity). However, this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire.

NSR Manual, at B.13-14.

This guidance is consistent with the regulatory definition of BACT, which requires the source to consider "application of production processes or available methods, systems and techniques" to control contaminants from a "proposed" source. Utah Admin. Code R307-401-2(1).

Applying EPA guidance to the permit review process for the SPC facility, the Executive Secretary recognized that while the selected CFB Boiler and IGCC both utilize coal as feedstock, they do so using very different methods. Having concluded that IGCC and the CFB Boiler were different process technologies, the Executive Secretary properly did not require that consider IGCC process technology in its analysis of BACT for the proposed SPC plant, as such would be a fundamental redefining of the design of the source.

EPA's Environmental Appeals Board has consistently affirmed EPA's policy that the BACT requirement not be used to redefine the basic design or scope of a proposed project. See In Re Knauf Fiber Glass, GMBH, 8 E.A.D. 121, 140 (EAB 1998); also see In the Matter of: Old Dominion Electric Cooperative Clover, Virginia, 3 E.A.D. 779, 793 n.38 (Adm'r 1992); and see In the Matter of: Pennsauken County, New Jersey, Resource Recovery Facility, 2 E.A.D. 667, 673 (Adm'r 1988). The NSR Manual recognizes that in order for the necessary case-by-case determination required by the BACT regulation to occur, the proposed source in any given case

must be clearly defined. In this case, the source as proposed by the applicant is a circulating fluidized bed coal-fired unit.

While EPA guidance does not preclude permitting authorities from exercising some discretion in this area, and some states have exercised this discretion to require that IGCC be considered as part of the BACT analysis.[2] On the other hand, in choosing not to use the BACT rule in such a manner, the Executive Secretary was in line with the EPA as well as permitting authorities in other states to consider the issue.[3]

9. Requiring Applicant to Redefine Source Would Violate State Law in Absence of Rulemaking

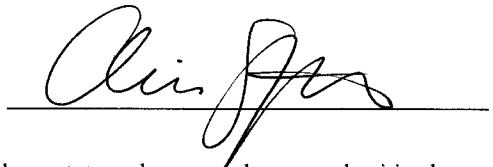
For the Executive Secretary to diverge from the stringency of the equivalent federal BACT rule would require compliance with U.C.A. § 19-6-106, and the rulemaking requirements as set forth in subparagraph (2) of that statute. The Board has not undertaken any such rulemaking on this question.

CONCLUSION

Based upon the foregoing, the Executive Secretary submits to the Board that both of these claims should be dismissed as a matter of law.

Respectfully submitted this 26th day of February, 2007.

MARK L. SHURTLEFF
ATTORNEY GENERAL



[2] Illinois, Montana and New Jersey are three states whose regulatory authorities have required consideration of IGCC as part of BACT.

[3] Wisconsin, Wyoming, and Kentucky are among those states who have determined not to include IGCC in the BACT analysis for a coal-fired power plant on the rationale that selection of IGCC as BACT would redefine the design of the proposed coal-fired plants. See Wisconsin Electric at 2005 WL 3450602. In Wisconsin, a review board held that IGCC does not qualify because IGCC cannot be applied to the installation as proposed "[r]ather IGCC is an altogether different method of generating electricity that would involve the wholesale substitution of one type of physical plant for another." Wisconsin Electric Power Co., 2005 WL 3450602 (Wisc. Div. Hrg. App. Feb. 3, 2005). An Environmental Appeals Board in Hawaii also concluded that regulations for determining BACT "do not mandate that the permitting authority redefine the source in order to reduce emissions." See In the Matter of Hawaiian Commercial & Sugar Co., PSD Appeal No. 92-1, 4 E.A.D. 95, 99-100, 1992 WL 191948 (July 20, 1992).

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Assistant Attorneys General
For the Executive Secretary
of the Air Quality Board

CERTIFICATE OF SERVICE

I hereby certify that on the 26th day of February, a true and correct copy of the foregoing Executive Secretary's Motion for Partial Judgment on the Pleadings was mailed, postage prepaid, and/or emailed to the following:

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BEFORE THE UTAH AIR QUALITY BOARD

In the Matter of: Unit 3, Intermountain Power Service, Millard County, Utah DAQE-AN0327010-04	EXECUTIVE SECRETARY'S MOTION FOR JUDGMENT ON THE PLEADINGS

Pursuant to Rule 12(c) of the Utah Rules of Civil Procedure, the Executive Secretary of the Utah Air Quality Board ("Executive Secretary") submits this Motion for Judgment on the Pleadings in Support of Motion for Judgment on the Pleadings pertaining to the Request for Agency Action filed by Sierra Club.

This motion is supported by the memorandum in support filed with this motion and all other pleadings on file with the Board in this action.

Dated this 26th day of February, 2007.

MARK L. SHURTLEFF
Utah Attorney General

Paul M. McConkie, Assistant Attorney General
Christian C. Stephens, Assistant Attorney General

CERTIFICATE OF SERVICE

I hereby certify that on this 26th day of February, 2007, I caused a copy of the foregoing to be mailed by United States Mail, postage prepaid, and/or emailed to the following:

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BEFORE THE UTAH AIR QUALITY BOARD

In the Matter of: Unit 3, Intermountain Power Service Corporation, Millard County, Utah DAQE-AN0327010-04	EXECUTIVE SECRETARY'S MEMORANDUM IN SUPPORT OF MOTION FOR PARTIAL JUDGMENT ON THE PLEADINGS

Pursuant to Rule 12(c) of the Utah Rules of Civil Procedure, the Executive Secretary of the Utah Air Quality Board ("Executive Secretary") submits this Memorandum in Support of its Motion for Partial Judgment on the Pleadings pertaining to Sierra Club's Request for Agency Action (the "RFA").

At issue in this proceeding is whether the Executive Secretary conducted the proper regulatory review in issuing an Approval Order (AO) to Intermountain Power Service Corporation (IPSC) to construct and operate an additional unit at the Intermountain Power Plant in Millard County, Utah. As the Executive Secretary will show, no genuine issues of material fact remain on the claims addressed in the motion, and consequently the Executive Secretary is entitled to judgment as a matter of law. Accordingly, the Executive Secretary respectfully submits that the accompanying motion for partial judgment on the pleadings should be granted.

INTRODUCTION

On October 15, 2004, the Executive Secretary issued an Approval Order to IPSC to construct and operate a third unit at the Intermountain Power Plant in Millard County, Utah. On November 16, 2004, Sierra Club filed a Request for Agency Action ("RFA") appealing the Approval Order. A hearing on the merits is set for November 2007. For purposes of limiting the evidentiary hearing to those claims where there exists a genuine issue of material fact, the Executive Secretary submits this memorandum in support of its motion for partial judgment on the pleadings.

STANDARD OF REVIEW

The Utah Rules of Civil Procedure allow a defendant to file a Motion for Judgment on the Pleadings pursuant to Rule 12(c) as follows:

> After the pleadings are closed but within such time as not to delay the trial, any party may move for judgment on the pleadings. If, on a motion for judgment on the pleadings, matters outside the pleadings are presented to and not excluded by the court, the motion shall be treated as one for summary judgment and disposed of as provided in Rule 56,and all parties shall be given reasonable opportunity to present all material made pertinent to such a motion by Rule 56.

A Rule 12(c) motion will be governed by the same standard as a Rule 12(b)(6) motion to dismiss, Seolas v. Bilzerian, 951 F. Supp. 978, 980 (D. Utah 1997) and the moving party must "clearly establish that no material issue of fact remains to be resolved and that he is entitled to judgment as a matter of law." 5C Wright & Miller, Federal Practice and Procedure § 1368 (2005).

The Board has a two-fold responsibility at a hearing on the merits: (1) to determine the facts and (2) to apply the law to those facts. Judgment on the pleadings is a procedural device which allows the Board to resolve claims "when moving party is entitled to judgment on the face

of the pleadings themselves." Mountain America Credit Union v. McClellan, 854 P.2d 590, 591 (Utah Ct. App. 1993). Judgment on the pleadings is appropriate when neither party disputes the material facts underlying their dispute. Town of Mapleton v. Kelly, 17 P. 52 (Utah 1911) (stating that presence of material facts prevents entry of judgment on the pleadings). "A 'material fact' is one which affects the rights or liabilities of the parties." Holland v. Iron Mining Co., 293 P.2d 700, 709 (Utah 1956). In other words, a material fact is one that must be determined by a fact finder at a hearing because the parties do not agree on the basic factual circumstances that have resulted in their dispute. Conversely, no issue of material fact exists when the parties agree as to the facts. If the Board grants this motion, the evidentiary hearing will be limited to claims where a factual dispute remains to be resolved.

STATEMENT OF UNDISPUTED FACTS

1. On December 16, 2002 and May 14, 2003, Intermountain Power Service Corporation submitted a Prevention of Significant Deterioration (PSD) permit application and its Notice of Intent (NOI) to construct an additional 950 megawatt (MW) pulverized coal-fired unit (Unit 3) at the Intermountain Power Plant near Delta, Utah.

2. PSD applies to new major sources or major modifications at existing sources located in areas designated as in attainment or as unclassifiable with the National Ambient Air Quality Standards (NAAQS). It requires the following:

- application of the "Best Available Control Technology" (BACT);
- an air quality analysis;
- an additional impacts analysis; and

- public involvement.

3. The proposed Unit 3 facility is considered a new major source for the pollutants carbon monoxide (CO), nitrogen oxides (NOx), sulfur dioxide (SO_2) and particulate matter (PM).

4. The area where the facility proposes to locate is designated as having attainment status for all pollutants.

5. Integrated Gasification Combined Cycle (IGCC) is a method of producing electricity by gasifying coal, removing pollutants before combustion, and then burning the syngas in a modified combined cycle gas-fired power plant. IGCC is not a control technology but rather a separate process from the proposed CFB technology.

6. The Executive Secretary did not require the applicant to include IGCC as part of its BACT analysis.

7. The Executive Secretary did not require regulation of carbon dioxide (CO_2) or other greenhouse gas emissions from the proposed unit.

8. A public comment period was held in accordance with Utah Admin. Code R307-401-4 and comments were received.

9. On October 15, 2004, Richard W. Sprott, Executive Secretary of the Utah Air Quality Board signed an Approval Order authorizing construction and operation of the proposed IPSC 950 mega-watt pulverized coal-fired unit.

ARGUMENT

This motion addresses the following two claims made by Sierra Club: (1) that the UDAQ was required to but failed to regulate carbon dioxide and other greenhouse gases; and (2) that the UDAQ was required to but failed to consider IGCC as part of the BACT analysis.

1. No Genuine Issue of Material Fact Exists on Either Claim.

Both of Sierra Club's claims are ripe for judgment on the pleadings because no genuine issue of material fact exists on either claim. That is, there is no dispute as to whether the Executive Secretary regulated greenhouse gases, nor is there a dispute as to whether he required that IGCC be considered as part of the BACT analysis. Both parties agree that he did not. The only point of dispute is whether on these two claims, the Executive Secretary properly applied the Board's rules.

2. State Law Sets Forth Stringency Requirements on the Board's Rulemaking Authority

Both claims share common underlying principles for points of reference. First, Utah law provides the Board with authority to make rules and a procedure for making those rules. Pursuant to statute and rule, the Air Quality Board and the Board's Executive Secretary administer the New Source Review program under authority delegated under the federal Clean Air Act (CAA) and under approval and oversight of the United States Environmental Protection Agency (EPA). The United States Supreme Court in Alaska v. EPA, 540 U.S. 461(2004) recognized that "Congress [ ] vested EPA with explicit and sweeping authority to enforce CAA requirements relating to the construction and modification of sources under the PSD program, including BACT" while noting at the same time "the need [by the EPA] to accord appropriate deference to States' BACT designations." See Alaska, at 490.

The Utah Air Conservation Act, § 19-2-104(1)(a), authorizes the Board to make rules "regarding the control, abatement, and prevention of air pollution." Per § 19-2-107(2)(g), the Executive Secretary may enforce those rules. However, Utah law limits the Board's rulemaking

authority. Utah Code Ann. § 19-2-106 limits the Board's authority to make rules that are more stringent than the existing federal regulations:

> (1) Except as provided in Subsection (2), no rule which the board makes for the purpose of administering a program under the federal Clean Air Act may be more stringent than the corresponding federal regulations which address the same circumstances. In making rules, the board may incorporate by reference corresponding federal regulations.
>
> (2) The board may make rules more stringent than corresponding federal regulations for the purpose described in Subsection (1), only if it makes a written finding after public comment and hearing and based on evidence in the record, that corresponding federal regulations are not adequate to protect public health and the environment of the state. Those findings shall be accompanied by an opinion referring to and evaluating the public health and environmental information and studies contained in the record which form the basis for the board's conclusion

Thus, unless the Board follows the requirements of § 19-2-106(2), the Board cannot make rules more stringent than the corresponding federal regulations addressing the same circumstances.

In the two claims that are at issue here, Sierra Club cites Utah's rule regarding Best Available Control Technology, or BACT. Under the Prevention of Significant Deterioration (PSD) program requirements, a prospective facility must employ the "best available control technology" for each regulated pollutant emitted. 42 U.S.C. § 7475(a)(4); Utah Admin. Code R307-401-6(1). Utah Admin. Code R307-101-2(4) defines Best Available Control Technology as:

> an *emission limitation* and/or other *controls* to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree or reduction of each pollutant subject to regulation under the Clean Air Act and/or the Utah Air Conservation Act *emitted from or which results from any emitting installation*, which the Air Quality Board, on a case-by-case basis taking into account energy, environmental and economic impacts and other costs, determines is achievable for *such installation* through application of production processes and available methods, systems and techniques, including fuel cleaning or treatment or

> innovative fuel combustion techniques *for control* of each such pollutant. In no event shall applications of BACT result in emissions of any pollutants which will exceed the emissions allowed by Section 111 or 112 of the Clean Air Act.

Id. (emphasis added).

Therefore, BACT is an "emission limitation" to control emissions from an "emitting installation" that the Executive Secretary "determines is achievable for such installation." Id. Utah's BACT rule essentially mirrors the federal BACT rule.[1]

3. The Executive Secretary Regulates Pollutants Based on Rules Promulgated by the Air Quality Board

Sierra Club Claim No. 3: UDAQ failed to address carbon dioxide and other greenhouse gases.

In this claim, Sierra Club makes the single factual allegation that the Executive Secretary did not require regulation of greenhouse gases. The Executive Secretary does not dispute this allegation and acknowledges that he did not require regulation of greenhouse gases. Thus, there is no genuine issue of material fact.

Although Sierra Club claims that both the Clean Air Act and the Utah Air Conservation Act require regulation of greenhouse gases, in its RFA Sierra Club provides no authority from either of those two acts to support its allegation. Neither the Clean Air Act nor the Utah Air Conservation Act lists greenhouse gases as regulated pollutants or contains any other requirement to regulate greenhouse gases. Regulation of greenhouse

[1] The federal BACT definition is found in 42 U.S.C. 7479(3) and provides in pertinent part: "The term best available technology means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, no a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant . . . ."

gases would require rulemaking by the Board, which has not occurred. Because the Board has not made any rules requiring the regulation of greenhouse gases, the Executive Secretary had no rule to enforce, and thus was correct as a matter of law in not requiring regulation of greenhouse gases in the IPSC Approval Order.

4. BACT Rule Applies to Regulated Pollutants

Further, Sierra Club's reliance on the BACT rule is misplaced and out of context. A full reading of the entire BACT rule shows that the "environmental impacts" considered during a BACT analysis apply to ". . . *each pollutant subject to regulation* under the Clean Air Act and/or the Utah Air Conservation Act . . . ." Utah Code Ann. R307-101-2(4) (emphasis added). Therefore, the BACT rule governs only pollutants that are already regulated, and the Executive Secretary was not allowed to consider any theoretical environmental impacts of greenhouse gases during the BACT analysis.

5. EPA Agrees with Executive Secretary on Regulating Greenhouse Gases

The Executive Secretary's position on this issue is consistent with that of the EPA, which has likewise deemed that it (EPA) has no authority under the Clean Air Act to regulate greenhouse gases. For instance, in an April 28, 1997 decision, the EPA's Environmental Appeals Board denied review of a PSD permit issued by the Hawaii Department of Health. See In re Kawaihae Cogeneration Project, 7 E.A.D. 107 (EAB 1997). In that appeal, the petitioners claimed that the Hawaii Department of Health improperly ignored greenhouse gases in its permit decision. Id. The Department responded that "there are no regulations or standards prohibiting, limiting or controlling

the emissions of greenhouse gases from stationary sources [in that] carbon dioxide is not considered a regulated air pollutant for permitting purposes." Id.

Then, in 1999, various groups petitioned EPA to initiate rulemaking to regulate greenhouse gases and EPA denied the petition on the basis that EPA has no authority to regulate greenhouse gases. See Control of Emissions from New Highway Vehicles and Engines, 68 Fed. Reg. 52,922 (denial of petition Sept. 8, 2003). Although various parties appealed the denial, the District of Columbia Court of Appeals upheld EPA's decision. See Commonwealth of Massachusetts v. EPA, 415 F.3d 50, 58 (D.C. Cir. 2005).

Based on the foregoing, the parties have no factual dispute, and thus there is no genuine issue of material fact. Accordingly, the Executive Secretary is entitled to judgment on this claim as a matter of law.

6. Sierra Club's IGCC Claim is Purely a Question of Law

Sierra Club Claim No. 1: UDAQ Failed to Consider Adequately Integrated Gasification Combined Cycle (IGCC) in its BACT Determination and Failed to Require the Production Process for IPP Unit 3.

In its RFA, Sierra Club takes the position that "UDAQ is required to evaluate this technology comprehensively as part of its BACT analysis" and that "consideration of [this] process design is a necessary part of its BACT analysis." Sierra Club RFA at 4. The narrowness of this claim presents only two potential questions of material fact: (1) whether IGCC is a separate process which would redefine the design of the source; and (2) whether the Executive Secretary required consideration of IGCC during the BACT stage of the permitting process.

"Redefining the source" is a term of art used by the EPA in its New Source Review Workshop Manual ("NSR Manual") which means to substitute one design process for an entirely different design process. The NSR Manual provides a concrete (and very similar to the situation here) example when it states that sources are not generally required to redefine the scope of their proposed facilities as part of the BACT analysis: "applicants proposing to construct a coal-fired electric generator would not be required as part of the BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity)." NSR Manual at B.13.

Sierra Club states in its RFA that it considers IGCC to be a "production process" and "*a method of producing electricity* by gasifying coal, removing pollutants – including greenhouse gases – before combustion, and then burning the 'clean' syngas in *a modified combined cycle gas-fired power plant*." Sierra Club RFA at 3 (emphasis added). The Executive Secretary concurs with this definition of the IGCC process. Because the Executive Secretary and the Sierra Club agree (1) on what IGCC is; and (2) that the Executive Secretary did not require its consideration, there remains no genuine issue of material fact. This claim, therefore, is purely a legal question of what the BACT rule requires.

The position taken by Sierra Club in its RFA that the BACT rule requires the Executive Secretary to require the applicant to consider IGCC in its BACT analysis makes this a very narrow issue of law for the Board to rule on because it takes any discretion away from the Executive Secretary. Sierra Club's position is contrary to not only the plain reading of the rule, but is also contrary to Utah law, EPA guidance, and to what regulatory authorities in most states to consider the issue have required.

7. <u>Sierra Club's Position on IGCC Claim is Contrary to Plain Reading of the BACT Rule</u>

Applying a plain reading to the BACT rule, BACT is an "emission limitation" to control emissions from an "emitting installation" that the Executive Secretary "determines is achievable for such installation . . . ." Utah Admin. Code R307-101-2(4). Utah Admin. Code R307-101-2 defines an installation as "a discrete process with identifiable emissions which may be part of a larger industrial plant. The BACT rule goes on to state that determining what is achievable "for such installation" includes "application of production processes and available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques". Utah Admin. Code R307-101-2(4). By definition, the BACT analysis is based on control technologies that can be applied to an installation that has already been identified. Otherwise, there is no emitting installation for which control technology can be analyzed.

On the other hand, Sierra Club's interpretation conflicts with both the definition of BACT as an "emission limitation" for the proposed installation, and the definition of installation, which states that an installation is a "discrete process with identifiable emissions." Utah Admin. Code R307-101-2.

8. <u>In Applying BACT Rule, Executive Secretary Follows EPA Guidance</u>

Because Utah's BACT rule essentially mirrors the federal BACT rule, and because of the restrictions on the Board's rulemaking authority (as it relates to equivalent federal rules), the Executive Secretary looks to the EPA's NSR Manual for guidance in administering Utah's New Source Review program. For the BACT analysis, the UDAQ employs EPA's recommended "top down" methodology. The United States Supreme Court has quoted at length from the NSR Manual, in describing the top-down method:

> . . . . the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent-or 'top'-alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not 'achievable' in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

Alaska Dept. of Envtl. Conservation v. EPA, 540 U.S. 461, 475-76 (2004) (hereinafter "ADEC") (quoting EPA's New Source Review Workshop Manual at B.2 (Draft Oct. 1990)).

To reiterate from paragraph 6 above, the NSR Manual also states that "production processes" or "available methods, systems and techniques" for pollutant reduction that would "redefine the design of the source" are not required to be included in the BACT analysis:

> [h]istorically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives. For example, applicants proposing to construct a coal-fired electric generator have not been required by EPA as part of a BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity). However, this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire.

NSR Manual, at B.13-14.

This guidance is consistent with the regulatory definition of BACT, which requires the source to consider "application of production processes or available methods, systems and techniques" to control contaminants from a "proposed" source. Utah Admin. Code R307-401-2(1).

Applying EPA guidance to the permit review process for the proposed IPSC Unit 3 facility, the Executive Secretary recognized that while the selected pulverized coal boiler (PC boiler) and IGCC both utilize coal as feedstock, they do so using very different methods. Having concluded that IGCC and the PC boiler were different process technologies, the Executive Secretary properly did not require that consider IGCC process technology in its analysis of BACT for the proposed Unit 3, as such would be a fundamental redefining of the design of the source.

EPA's Environmental Appeals Board has consistently affirmed EPA's policy that the BACT requirement not be used to redefine the basic design or scope of a proposed project. See In Re Knauf Fiber Glass, GMBH, 8 E.A.D. 121, 140 (EAB 1998); also see In the Matter of: Old Dominion Electric Cooperative Clover, Virginia, 3 E.A.D. 779, 793 n.38 (Adm'r 1992); and see

In the Matter of: Pennsauken County, New Jersey, Resource Recovery Facility, 2 E.A.D. 667, 673 (Adm'r 1988). The NSR Manual recognizes that in order for the necessary case-by-case determination required by the BACT regulation to occur, the proposed source in any given case must be clearly defined. In this case, the source as proposed by the applicant is a pulverized coal-fired unit.

While EPA guidance does not preclude permitting authorities from exercising some discretion in this area, and some states have exercised this discretion to require that IGCC be considered as part of the BACT analysis.[2] On the other hand, in choosing not to use the BACT rule in such a manner, the Executive Secretary was in line with the EPA as well as permitting authorities in other states to consider the issue.[3]

9. Requiring Applicant to Redefine Source Would Violate State Law in Absence of Rulemaking

For the Executive Secretary to diverge from the stringency of the equivalent federal BACT rule would require compliance with U.C.A. § 19-6-106, and the rulemaking requirements as set forth in subparagraph (2) of that statute. The Board has not undertaken any such rulemaking on this question.

CONCLUSION

Based upon the foregoing, the Executive Secretary submits to the Board that both of these claims should be dismissed as a matter of law.

Respectfully submitted this 26th day of February, 2007.

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[2] Illinois, Montana and New Jersey are three states whose regulatory authorities have required consideration of IGCC as part of BACT.

[3] Wisconsin, Wyoming, and Kentucky are among those states who have determined not to include IGCC in the BACT analysis for a coal-fired power plant on the rationale that selection of IGCC as BACT would redefine the design of the proposed coal-fired plants. See Wisconsin Electric at 2005 WL 3450602. In Wisconsin, a review board held that IGCC does not qualify because IGCC cannot be applied to the installation as proposed "[r]ather IGCC is an altogether different method of generating electricity that would involve the wholesale substitution of one type of physical plant for another." Wisconsin Electric Power Co., 2005 WL 3450602 (Wisc. Div. Hrg. App. Feb. 3, 2005). An Environmental Appeals Board in Hawaii also concluded that regulations for determining BACT "do not mandate that the permitting authority redefine the source in order to reduce emissions." See In the Matter of Hawaiian Commercial & Sugar Co., PSD Appeal No. 92-1, 4 E.A.D. 95, 99-100, 1992 WL 191948 (July 20, 1992).

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I hereby certify that on the 26th day of February, a true and correct copy of the foregoing Executive Secretary's Motion for Partial Judgment on the Pleadings was mailed, postage prepaid, and/or emailed to the following:

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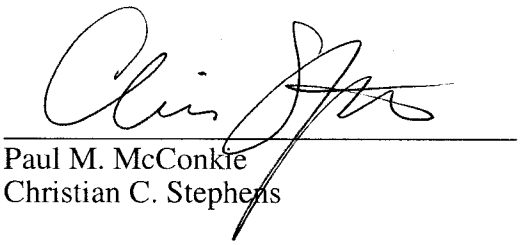

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BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – the Sevier Power Company, 270 MW Coal-Fired Power Plant, Sevier County Project Code: N2529-001 DAQE-AN2529001-04	**PACIFICORP'S MOTION FOR JUDGMENT ON THE PLEADINGS**

Pursuant to Rule 12(c) of the Utah Rules of Civil Procedure, PacifiCorp hereby submits this Motion for Judgment on the Pleadings regarding the Sierra Club's Request for Agency Action. This Motion pertains to the following two issues set forth in Sierra Club's Request for Agency Action:

1. The Executive Secretary failed to address carbon dioxide and other greenhouse gas emissions in issuing the Sevier Power Company PSD permit.
2. The Executive Secretary failed to consider adequately Integrated Gasification Combined Cycle in its BACT determination for Sevier Power Company facility.

This Motion is supported by a Memorandum in Support filed herewith and incorporated by reference herein, and all other pleadings on file with the Utah Air Quality Boar in this matter.

Dated this 26th day of February, 2007.

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I hereby certify that on this 26th day of February, 2007, I emailed and mailed a true and correct copy of the foregoing **PACIFICORP'S MOTION FOR JUDGMENT ON THE PLEADINGS** to the following:

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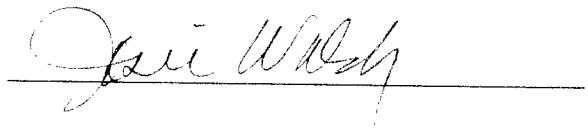

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BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – the Sevier Power Company, 270 MW Coal-Fired Power Plant, Sevier County Project Code: N2529-001 DAQE-AN2529001-04	**PACIFICORP'S MEMORANDUM IN SUPPORT OF MOTION FOR JUDGMENT ON THE PLEADINGS**

PacifiCorp requests the Utah Air Quality Board (the "Board") to dismiss, as a matter of law, two of the issues raised in the Request for Agency Action filed by the Sierra Club on November 12, 2006 ("Request for Agency Action"): (i) whether Integrated Gasification Combined Cycle ("IGCC") technology must be considered during the Best Available Control Technology ("BACT") analysis; and (ii) whether "carbon dioxide and other greenhouse gas emissions" ("GHG") must be considered or regulated as part of the air permit process.[1]

[1] The Request for Agency Action was submitted jointly by the Sierra Club and by the Grand Canyon Trust., but on January 25, 2007, the Grand Canyon Trust filed its Notice of Withdrawal from this proceeding. PacifiCorp's Petition to Intervene was granted by the Utah Air Quality Board at its February 7, 2007 hearing.

I. INTRODUCTION

The parties and the Board have consented to PacifiCorp participating in this matter in regard to the two issues noted above. This status provides for the filing of dispositive motions, and in that light PacifiCorp submits this Memorandum in Support of its Motion for Judgment on the Pleadings.

II. STANDARD OF REVIEW

Rule 12(c) of the Utah Rules of Civil Procedure allow a party to file a Motion for Judgment on the Pleadings, which is a mechanism the Board may use to dispose of issues that are legal rather than factual in nature. 5C Wright & Miller, Federal Practice and Procedure § 1367 (2005). For example, legal issues would include whether the law requires the regulation of GHG or the inclusion of IGCC in a BACT analysis, whereas factual issues would include whether GHG is harmful to the environment or whether IGCC is economically feasible. To narrow the issues that will ultimately have to be addressed at the hearing in this matter, the Board can use a judgment on the pleadings at this early dispositive motion stage to resolve and eliminate those issues or claims "when the moving party is entitled to judgment on the face of pleadings themselves." *Mountain America Credit Union v. McClellan*, 854 P.2d 590, 591 (Utah Ct. App. 1993). Accordingly, as to Sierra Club's claims that are legal in nature, such as Claim #1 and #2, the Board need only apply the law and issue a decision, thus eliminating the time and expense of addressing that issue at the final hearing.

III. BURDEN OF PROOF

It is the petitioner, Sierra Club, that carries the burden of proof in this administrative adjudication, and the "proper standard of proof in the administrative context is generally the 'preponderance of the evidence' standard." *Harkin Southwest Corp. v. Board of Oil, Gas and Mining*, 920 P.2d 1176, 1182 (Utah 1996). In addition, the petitioner, Sierra Club, must

overcome the presumption of correctness which accompanies the actions of an administrative agency, which means that the Executive Secretary's "actions [in issuing an air permit to the Sevier Power Company are] endowed with a presumption of correctness and validity." *Cottonwood Heights Citizens Ass'n. v. Board of Comm'rs. of Salt Lake County*, 593 P.2d 138, 140 (Utah 1979).

IV. BACKGROUND

A. **Greenhouse Gas Emissions (Claim #1)**: PacifiCorp's legal argument is very simple -- neither the federal Clean Air Act nor the Utah Air Conservation Act or its implementing regulations authorize or require the State of Utah to regulate GHG in connection with an air permit or otherwise. Under the Utah Air Conservation Act, the Board may make rules "regarding the control, abatement, and prevention of air pollution," and the Executive Secretary may, as authorized by the Board, enforce such rules as the Board may make. Utah Code Ann. §§ 19-2-104(1)(a) & 107(2)(g). However, in its discretion, the Board has never made any such rules for the regulation of GHG. Accordingly, the Executive Secretary was not authorized or required to address GHG in connection with its issuance of the AO. It is this legal issue -- whether any existing statute or regulation required the Executive Secretary to address GHG -- that is the subject of Sierra Club's Claim #1.

B. **Integrated Gasification Combined Cycle (Claim #2)**: Under the Clean Air Act's New Source Review provisions and similar provisions of the Utah Air Conservation Act, a party intending to construct a "major" new source in a NAAQS attainment area must first obtain a PSD permit. 42 U.S.C. § 7475(a). Under the PSD requirements the applicant must demonstrate, among other things, that the new source will employ BACT for each criteria pollutant emitted. 42 U.S.C. § 7475(a)(4); Utah Admin. Code R307-401-6(1).

Under the applicable Utah regulations, BACT is defined as follows:

> [A]n emission limitation and/or other controls to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree or reduction of each pollutant subject to regulation under the Clean Air Act and/or the Utah Air conservation Act emitted from or which results from any emitting installation, which the Air Quality Board, on a case-by-case basis taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such installation through application of *production processes and available methods, systems, and techniques*, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant...."

Utah Admin. Code. R307-101-2(4)(emphasis added)[2]

A "top-down" method for determining BACT is recommended by EPA, and required by Utah. *See* EPA Memorandum re Improving NSR Implementation; 61 Fed. Reg. at 38, 272-73; Utah NOI Guide, Form 1b. This top-down method includes 5 steps: (1) identify all available control technologies (the "First Step"), (2) eliminate technically infeasible control technologies, (3) rank remaining technologies by effectiveness, (4) evaluate the most effective controls (assessing the energy, environmental and economic impacts), and (5) select the most effect remaining option. EPA's New Source Review Workshop Manual ("NSR Manual"), at B.5. In the course of the BACT analysis, one or more of the options may be eliminated if they are demonstrated to be technically infeasible or have unacceptable energy, environmental or economic impacts on a case-by-case basis. However, the First Step is to identify all available control technology options.[3] It is this legal issue -- whether the Executive Secretary was required to include IGCC in this First Step -- that is the subject of Sierra Club's Claim #2.

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[2] Utah's BACT definition is substantially similar to the federal definition. *See* 42 U.S.C. § 7479(3).

[3] Although not material or necessary to the resolution of this legal issue of whether the Executive Secretary was required to include IGCC in this First Step, the "available" options that must be identified are only "those control technologies or techniques with a practical potential for application to the emission unit." NSR Manual, at B.5. The NSR Manual further provides that applicants are only expected to identify "demonstrated and potentially applicable control technology alternatives." NSR Manual at B.11. "Technologies that have not been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice." NSR Manual, at B.11; *see also Nance v. EPA*, 645 F.2d 701 (9th Cir. 1981) (*quoting Vermont Yankee Nuclear Power Corp. v. NRDC*, 435 U.S. 519 (1978) ("If the technology is not available, the permit applicant is under no duty to consider it in the BACT

V. ARGUMENT

A. Greenhouse Gas Emissions (Claim #1)

In its Request for Agency Action, Sierra Club asserts that "[p]ursuant to the [federal] Clean Air Act and Utah Air [Conservation] Act and its implementing rules, the State of Utah has the legal obligation to regulate greenhouse gases," and that under the definition of BACT, "Utah is required to consider . . . greenhouse gas emissions, when determining BACT for a facility."

1. Neither the Clean Air Act, nor the Utah Air Conservation Act or its Implementing Regulations, Authorize or Require Utah to Regulate GHG

Under the federal Clean Air Act, EPA is charged with the task of identifying certain air pollutants that "cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare," and then establishing national ambient air quality standards ("NAAQS") to protect against adverse effects from each identified pollutant. 42 U.S.C. § 7408(a)(1). Significantly, EPA has not identified carbon dioxide or other GHG as a regulated air pollutant, and has not established any NAAQS for GHG. The Clean Air Act does not obligate Utah or any other state to regulate GHG. Sierra Club cannot cite to any particular provision of the Clean Air Act obligating the regulation of GHG. *In re: Kawaihae Cogeneration* Project, 1997 WL 221391, 7 E.A.D. 107 (E.P.A. April 28, 1997)("[A]t this time there are no regulations or standards prohibiting, limiting or controlling the emissions of greenhouse gases from stationary sources. Carbon dioxide is not considered a regulated air pollutant for permitting purposes."). Even more significantly, although Sierra Club has been urging courts around the

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analysis.")); *In re Spokane Regional Waste-to-Energy Applicant, PSD App. No. 88-12,* 1989 WL 266360 (EPA June 9, 1989)("A technology is obviously not available in any meaningful sense if knowledge about its effect on emissions, in the particular configuration in which it would be employed, is so incomplete as to be unusable"). Because Sierra Club cannot not offer any evidence that IGCC technology is available as a control technology option, IGCC cannot be deemed an "available" control technology.

country to infer such an obligation into the Clean Air Act, Sierra Club has not cited to any judicial decision that does so. Moreover, EPA, the federal agency that administers the Clean Air Act, has never used that Act or any other authority to try to regulate GHG.

Similarly, neither the Utah Air Conservation Act nor its implementing regulations obligate Utah to regulate GHG. Again, Sierra Club has not cited to any particular provision of the Utah Air Conservation Act or its implementing regulations obligating the regulation of GHG, and has not cited to any judicial decision wherein a court has inferred such an obligation. Moreover, the Utah Division of Air Quality ("UDAQ"), the state agency that administers the Utah Air Conservation Act and its implementing regulations, has never used that Act or those regulations, or any other authority, to try to regulate GHG.

Under the Utah Air Conservation Act, the Board may make rules "regarding the control, abatement, and prevention of air pollution," and the Executive Secretary may, "as authorized by the Board," enforce such rules as the Board may make. Utah Code Ann. §§ 19-2-104(1)(a) & 107(2)(g). However, in its discretion, the Board has never made any such rules for the regulation of GHG, and has never authorized the Executive Secretary to enforce the regulation of GHG. Accordingly, the Executive Secretary has never been authorized, let alone required, to address GHG in connection with the issuance of an AO.

Although nothing in the applicable federal or state statutory or regulatory schemes obligates Utah to regulate GHG, the Utah legislature could enact legislation and/or the Board could make administrative rules to regulate GHG if either so chooses. In fact, Utah is currently in the process of formulating an action plan for ascertaining if and how it will address GHG. UDAQ, in conjunction with the Department of Natural Resources, Office of Energy, has undertaken an emissions inventory of the important sources of greenhouse gases. UDAQ has

completed the basic inventory, and the Office of Energy is now in the process of completing the final report. This inventory is the first step in what is envisioned to be a multi-phase program to develop a state action plan. The second step will use this baseline inventory to assist in the development and analysis of policy options, with the final step being the formulation of a state action plan. *See* www.airquality.utah.gov/Planning/Emission- Inventory/Greenhousegas.htm. That action plan, and/or other initiatives, may or may not result in legislation or administrative rules to regulate GHG; however, unless and until such legislation or rules are adopted, the Executive Secretary is neither required nor authorized to regulate GHG.

2. Under the Definition of BACT, Utah is Not Required to Consider GHG When Determining BACT

Sierra Club contends that "pursuant to the definition of 'best available control technology" (BACT), Utah Admin. Code R307-101-2, Utah is required to consider other environmental impacts, such as green house gas emissions, when determining BACT for a facility." First, the referenced definition is just that – a definition. It is not a command or a requirement. The command aspect of the PSD program is set forth elsewhere in the regulatory scheme. *See* Utah Admin. Code R307-401-6(1) (requiring the applicant to demonstrate that "the degree of pollution control for emissions . . . is at least best available control technology . . . "); 42 U.S.C. § 7475(a)(4)("No major emitting facility . . . may be constructed . . . unless – the proposed facility is subject to the best available control technology for each pollutant subject to regulation."). Nothing in this definitional provision can be construed as an affirmative command or requirement.

Second, a cursory examination of the regulatory definition undermines Sierra Club's contention. Under the regulatory language, BACT means:

> [A]n emission limitation and/or other controls to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree or

> reduction of each pollutant subject to regulation under the Clean Air Act and/or the Utah Air conservation Act emitted from or which results from any emitting installation, which the Air Quality Board, on a case-by-case basis taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such installation through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant...."

Utah Admin. Code. R307-101-2(4). Nothing in the language of this definition requires Utah to consider GHG in its BACT determination. Neither UDAQ, the Executive Secretary nor the Board has ever construed the BACT definition in this manner so as to require consideration of GHG. Moreover, neither the Utah Supreme Court nor any other Utah court has ever construed the BACT definition in this manner so as to require consideration of GHG.

3. "More Stringent" State Rules are Statutorily Prohibited

The Utah Code, Section 19-2-106, prohibits the Board from making any rule "for the purpose of administering a program under the federal Clean Air Act" that would be "more stringent than the corresponding federal regulations which address the same circumstances."[4] The creation of a new state rule that would be more stringent than the current federal regulations (which do not regulate GHG) would violate this statutory prohibition. The Board should abide by both the letter and the spirit of this prohibition against a new more stringent rule that would regulate GHG.

4. De Facto Rulemaking Should be Avoided: Sierra Club Should be Using Legislation and/or Administrative Rulemaking, rather than this Administrative Adjudication, to Pursue its Objective

The cart cannot be put before the horse – Sierra Club complains that the Executive Secretary failed to consider GHG in connection with the issuance of the AO, and then complains

[4] The only exception to this prohibition is if the Board "makes a written finding after public comment and hearing and based on evidence in the record, that corresponding federal regulations are not adequate to protect public health and the environment of the state. Utah Code Ann. §19-2-106(2). Of course, here, the Board has not come to any such conclusion, and certainly has not made any such written findings after public comment and hearing.

that Utah should be required to regulate GHG. Sierra Club is attempting to use the administrative adjudication process to achieve an objective that should be pursued through the legislative or administrative rulemaking process. If Sierra Club thinks GHG should be regulated, it should pursue a legislative remedy or initiate an administrative rulemaking. If, as all the parties except Sierra Club contend, the Utah Air Conservation Act does not currently obligate Utah to regulate GHG, Sierra Club should pursue state legislation as has been done in other states. On the other hand, if, as Sierra Club contends, the Utah Air Conservation Act already obligates Utah to regulate GHG, then Sierra Club should initiate a rulemaking procedure, pursuant to the Utah Administrative Rulemaking Act, Admin. Code Ann. §§63-46a-1 et seq., to develop appropriate implementing regulations.

Courts and commentators have long "shown near unanimity in extolling the virtues of the rule-making process over the process of making 'rules' through case-by-case adjudication." Shapiro, *The Choice of Rulemaking and Adjudication in the Development of Administrative Policy*, 78 Harv. L. Rev. 921 (1965). *See also* Davis & Pierce Treatise § 6.8 ("when an agency ... announces a generally applicable rule in the process of adjudicating a particular dispute, only the parties to the dispute have a role in shaping the 'rule,' even though it ultimately affects thousands of regulatees and beneficiaries who had no opportunity to participate in the process of its formulation."); Davis & Pierce Treatise § 6.4 ("[m]any legislative rules 'interpret' statutory language, in the sense that they announce the agency's construction of a statute it has responsibility to administer.") Sierra Club's attempt to persuade the Board to take this dramatic step toward regulating GHG, through this Sevier Power-specific adjudication, could significantly affect the entire regulated community. Significant and broadly applicable public policy issues such as this, however, are best resolved openly by legislation or rulemaking, rather than through

a case-specific adjudication. The Board should avoid the sort of de facto rulemaking that Sierra Club is suggesting.

B. **Integrated Gasification Combined Cycle (Claim #2)**

In its Request for Agency Action, Sierra Club asserts that the Executive Secretary was "required" to consider IGCC in its BACT analysis, but failed to do so. Sierra Club asks the Board to reinterpret the definition of BACT set forth in the applicable state regulation so as to require a proposed power plant that has already selected another type of electrical production technology (in this case, a CFB Boiler coupled with an electrical generator) to include an altogether different technology (in this case, IGCC) in the BACT analysis.[5]

If the Board were to accept Sierra Club's new interpretation, the practical effect could be very far reaching. Sierra Club argues that, as a matter of law – IGCC must be considered for any proposed project that intends to use coal for fuel, not just the Sevier Power Facility. If Sierra Club's new interpretation of the existing regulation is accepted for the Sevier Power Facility, that same interpretation may be applied to every other coal plant which seeks an AO in Utah. *See Salt Lake Citizen's Congress v. Mountain States Tel. & Tel. Co.*, 846 P. 2nd 1245, 1252 (Utah 1992)("Administrative agencies, like courts, have authority to establish rules of law and they do so in two ways by promulgating rules and by issuing decisions as a necessary incidence of adjudication. Rules of law developed in the context of agency adjudication are as binding as those promulgated by agency rule making; thus, rules of law established by adjudication apply to the future conduct of all persons subject to the jurisdiction of an administrative agency."); Kenneth Cup Davis & Richard J. Pierce, Administrative Law Treatise ("Davis & Pierce

[5] PacifiCorp is not opposed to the use of IGCC as a generating technology. Indeed, PacifiCorp's most recent Integrated Resource Plan includes IGCC among its prospective generating resources. PacifiCorp is adamantly opposed, however, to IGCC being required as part of a BACT analysis for a proposed facility simply because it intends to use coal as a fuel source.

Treatise") § 11.5 (4th ed. 2002) (agencies must generally follow their own precedents or interpretations, or explain why they have departed from them); *Atchison, Topeka & Santa Fe R. v. Wichita Bd. Of Trade*, 412 U.S. 800, 808 (1973).

1. BACT is Not a Means to Redefine the Source

By claiming that the Executive Secretary should have included IGCC in its BACT analysis, Sierra Club is arguing that a BACT review can be used as a means to force an applicant to redefine the proposed source. This interpretation is contrary to the plain language of the BACT requirement, established federal policy, the reiteration by EPA of that federal policy, and established Utah state policy.

a. The BACT Definition: The BACT definition requires that "production processes and available methods, systems and techniques" that are potentially applicable to the proposed source be included in a BACT analysis. However, BACT does not require that altogether different "alternatives" to the proposed source, that would replace the proposed source with a different type of source, be included. Instead, the BACT analysis need only include the "available control technologies" for the particular emission source that the applicant has elected to propose.[6] In this case, the applicant has not proposed a geo-thermal source, a gas-fired source, or an IGCC source; rather, Sevier Power has elected to propose a CFB Boiler source. *In re Spokane Regional Waste-to-Energy Applicant, PSD App. No. 88-12,* 1989 WL 266360, n.7 (EPA June 9, 1989) ("EPA has not required a PSD applicant to change the fundamental scope of its project.").[7]

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[6] Under the well-established permitting process, the applicant proposes the particular source, and then, through the BACT process, an appropriate emission control is put into place. It is the prerogative of the applicant to propose the type of source, whether gas-fired, IGCC, or some other source, and then, through the BACT process, an appropriate emission control specifically tailored to the selected source is put into place.

[7] It is herein that Sierra Club misapplies the BACT process. BACT requires that "available control technologies" be considered, not every other conceivable type or source of combustion.

b. Established Federal Policy: Under the long-established practice of the EPA, the applicant proposes the particular type of source, and then through the BACT analysis the applicant identifies available control technologies for the particular type of source proposed.[8] *In the Matter of: Hawaiian Commercial & Sugar Co.*, 1992 WL 191948, 4 E.A.D. 95 (E.P.A. July 20, 1992); *In re: Hillman Power Co., L.L.C.*, 2002 WL 1822719 (E.P.A. July 31, 2002). As explained in EPA's NSR Manual, "[h]istorically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives. For example, applicants proposing to construct a coal-fired electric generator, have not been required by EPA as part of a BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product." NSR Manual, at B.13. Sierra Club should not be allowed to misuse the First Step of the BACT process as a tool to force an applicant to change "the emission source in question," to "redefine the source" or to "change the fundamental scope of its project." IGCC is a

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[8] In *In re Pennsauken County, New Jersey Resource Recovery Facility*, PSD Appeal No. 88-8, 1988 WL 249035 (EPA November 10, 1988), the EPA's Environmental Appeals Board ("EAB") clarified that "[t]he first step in this approach is to determine, *for the emission source in question*, the most stringent control available . . . . *[T]he conditions themselves are not intended to redefine the source*, as petitioner [] would have them do. In other words, *the source itself is not a condition of the permit.*" The petitioner's "fundamental objections to the ... permit [we]re not with the control technology, but rather, with the municipal waste combustor itself." The petitioner urged the rejection of the proposed waste combustor in favor of co-firing a mixture of refuse and coal at existing power plants. The EAB held that such objections to the source proposed, rather than to the control technologies identified, were "beyond the scope of this proceeding and therefore are not reviewable. Under 40 C.F.R. § 124.19, the review is restricted to the 'conditions' in the permit." The decision goes on to provide that "[t]he permit conditions that define these systems are imposed on the source as the applicant has defined it. Although imposition of the conditions may, among other things, have a profound effect on the viability of the proposed facility as conceived by the applicant, the conditions themselves are not intended to redefine the source, as petitioner [] would have them do. In other words, the source itself is not a condition of the permit." (emphasis added). *See also* In *Spokane Regional Waste-to-Energy*, PSD Appeal No. 88-12, 1989 WL 266360 (EPA June 9, 1989)(In framing the scope of the first step of the analysis (identifying "all available control technologies"), the EAB stated that "a technology is obviously not available in any meaningful sense if knowledge about its effect on emissions, *in the particular configuration in which it would be employed*, is so incomplete as to be unusable." (emphasis added)); *In re Brooklyn Navy Yard Resource Recovery Facility*, PSD App. No. 88-10, 1992 WL 80946 (EPA February 28, 1992)(EAB stated that its "decision to remand this permit for consideration of source separation for NOx control is *not intended to result in any reconfiguration of the Brooklyn facility or significant change in its planned usage.*")(emphasis added)).

fundamentally different type of source than the proposed CFB Boiler,[9] and Sierra Club's suggested reinterpretation of the BACT requirement would impermissibly require the applicant to redefine the proposed source.

c. EPA's Reiteration of Federal Policy: In a December 13, 2005 letter from Stephen D. Page, Director of EPA's Office of Air Quality, Planning and Standards, attached hereto as Exhibit A, EPA reiterated its long-established interpretation of the BACT definition and its policy of not requiring IGCC to be considered in such BACT analyses ("EPA's Reiteration Letter"). The Reiteration Letter, "based on prior EPA policy statements and adjudicatory decisions," reflects EPA's established view of how the applicable statutes and regulations should be interpreted and applied. Although the Reiteration Letter was not issued by EPA as a new regulation, and by itself does not create any new legally binding effect on the Board, the Executive Secretary or any other regulated entity or person, the Reiteration Letter does reflect longstanding federal policy.[10]

In the Reiteration Letter, EPA confirmed that "[a]s noted 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*. For example, we do not require applicants proposing to construct a coal-fired steam electric generator to consider building a natural gas-fired combustion turbine as part of a BACT analysis, even though the turbine may be inherently less polluting . . . ." (emphasis added). EPA

[9] Generating electrical power through using coal and IGCC technology involves "gasifying" coal and then combusting the gas to power a gas turbine, while the exhaust gases are heat exchanged with water/steam to generate additional electricity through a steam turbine. This process is very different from a CFB Boiler with its associated steam turbines currently proposed by Sevier Power.

[10] On September 25, 2006, the EPA entered into an agreement with several environmental organizations wherein EPA readily stipulated that the December 13, 2005 document was not promulgated as a regulation under the Clean Air Act, was not a final agency action, and by itself did not created any rights, duties, obligations, or any other legally binding effects on EPA, the states, tribes, any regulated entity or any person.

concludes by stating that "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 . . . ." Sierra Club's suggested reinterpretation contradicts established EPA decisions and guidance as reflected in EPA's Reiteration Letter.

d. UDAQ Policy: The Executive Secretary and UDAQ have already twice taken the position that the BACT requirement does not oblige the applicant for a particular proposed source to consider using a completely different source as a means to reduce emissions.[11] More specifically, UDAQ has taken the position that the BACT requirement does not require the applicant for a coal-fueled electricity generating facility to consider using IGCC. Administrative agencies must generally follow their own precedents or interpretations, or explain why they have departed from them. Davis & Pierce Treatise, § 11.5; *Atchison,* 412 U.S. at 808; *JSG Trading Corp. v. Dep't of Agriculture*, 176 F.3d 536 (D.C. Cir. 1999) (reversing agency for construing new definition of statutory term without explanation); *Contractors Transport Corp. v. U.S.*, 537 F.2d 1160, 1162 (4th Cir. 1976) ("the grounds for an agency's disparate treatment of similarly situated applicants must be reasonably discernible from its report and order"). The Board should follow the established interpretation on this IGCC issue. In light of the established federal precedent, and the EPA Reiteration Letter reflecting the established federal precedent,

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[11] In this matter UDAQ previously determined that "BACT is used as a control technology *after* selection of the process to be so controlled. In BACT guidance issued by EPA it states that, '[h]istorically, EPA has not considered the BACT requirement as a means to redefine the design of the source...'" September 27, 2004 Memorandum to Sevier Power Plant File, at 30 (emphasis added). UDAQ went on to conclude that "[t]he process chosen by the source needs to be made based on the requirements of the source and the site selected for its installation. Control techniques are *then* applied to reduce the emissions of that process." *Id.* (emphasis added).

UDAQ has also determined in another matter that IGCC is not BACT because such would require "redefining the design of the source," and because IGCC is not a "control technology" under BACT. October 14, 2004 Memorandum to IPSC File, at 4. UDAQ went on to conclude that "[n]either federal nor state clean air laws require this." *Id.* at 5. " In refuting claims that IGCC should be included in the BACT analysis, UDAQ also relied on EPA's statements on the subject. "Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives." *Id.* at 4.

and the established state precedent, it would be very difficult for the Board to articulate an explanation justifying a departure from those precedents.[12]

2. "More Stringent" State Rules are Statutorily Prohibited

As addressed above in more detail, the Utah Code, Section 19-2-106, prohibits the Board from making any rule "for the purpose of administering a program under the federal Clean Air Act" that would be "more stringent than the corresponding federal regulations which address the same circumstances." The Board's creation of a new state rule that would be more stringent than the long-established federal policy would violate this statutory prohibition.

3. De Facto Rulemaking Should be Avoided: Sierra Club Should be Using Legislation and/or Administrative Rulemaking rather than this Administrative Adjudication

Sierra Club's attempt to reinterpret the applicable state regulation is tantamount to a rule-making in that the existing state regulation, which has never been interpreted to require consideration of IGCC as part of a BACT analysis, would be fundamentally changed. As addressed above in more detail, courts and commentators have long "shown near unanimity in extolling the virtues of the rule-making process over the process of making "rules" through case-by-case adjudication." Shapiro, *The Choice of Rulemaking and Adjudication in the Development of Administrative Policy*, 78 Harv. L. Rev. 921 (1965). *See also* Davis & Pierce Treatise § 6.8. This significant and broadly applicable public policy issue should be resolved openly through

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[12] Other states that have encountered this issue have expressly rejected Sierra Club's reinterpretation of the BACT requirement. For example, after an environmental group challenged the Wisconsin Department of Natural Resources' approval of a proposed coal fired unit for failure to have considered IGCC in its BACT analysis, an Administrative Judge confirmed that the State was not required to consider IGCC. *See* Wisconsin Division of Hearings and Appeals, Case No. IH-04-03 (February 3, 2005). *See also* West Virginia Department of Air Quality, Response to Comments 2, at 35 (West Virginia Department of Air Quality, in considering a PSD permit application for the Longview power plant, concluded that IGCC was not required to be included in the BACT analysis.). *See also* transcript of the Board's May 10, 2006 hearing in Richfield, Utah, at p.64 (regarding similar decisions by Arkansas, West Virginia, Kentucky, Indiana, Florida, Arizona, Wyoming, Colorado and others). Of the many states to have considered the issue, only Illinois and New Mexico have decided to exercise their regulatory discretion to consider IGCC in a BACT analysis.

legislation or rulemaking, rather than through a case-specific adjudication. The Board should decline to indulge in this sort of de facto rulemaking.

VI. CONCLUSION

Sierra Club's Claim #1 and Claim #2 involve no factual issues, but present only the legal issues of whether the Executive Secretary was required to address GHG, and to consider IGCC in the BACT analysis. Under the applicable statutes and regulations, the Executive Secretary was neither required nor authorized to address GHG. Similarly, under the applicable regulatory requirement, federal precedent (recently restated in EPA's Reiteration Letter), and state precedent, the Executive Secretary was not required to include IGCC in its BACT analysis. Accordingly, because Sierra Club has failed to meet its burden of showing that the Executive Secretary erred on these two legal issues, PacifiCorp respectfully requests that the Board grant its Motion for Judgment on the Pleadings as to Sierra Club's Claim #1 and Claim #2.

Dated this 26th day of February, 2007.

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CERTIFICATE OF SERVICE

I hereby certify that on this 26th day of February, 2007, I emailed and mailed a true and correct copy of the foregoing **PACIFICORP'S MEMORANDUM IN SUPPORT OF MOTION FOR JUDGMENT ON THE PLEADINGS** to the following:

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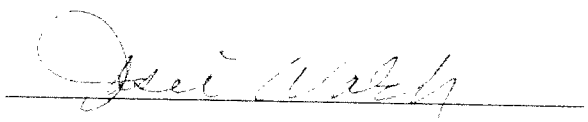

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BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – the Sevier Power Company 270 MW Coal-Fired Power Plant, Sevier County Project Code: N2529-001 DAQE-AN2529001-04	:	

In Re: Approval Order – PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station, Millard County, Utah Project Code: N0327-010 DAQE-AN0327010-04	:	CONSOLIDATED OPPOSITION TO MOTIONS FOR JUDGMENT ON THE PLEADINGS

The Utah Chapter of the Sierra Club (Sierra Club) respectfully submits the following Consolidated Opposition to the Motions for Judgment on the Pleadings filed in these two matters by the Executive Secretary of the Utah Air Quality Board (Executive Secretary), Sevier Power Company (SPC), PacifiCorp, and Intermountain Power Service Corporation (IPSC), together with supporting exhibits. As described below, the Executive Secretary, SPC, PacifiCorp, and IPSC (collectively referred to as the "Proponents" because they support the Division of Air Quality (DAQ)'s position) raise

identical issues in their five briefs, and Sierra Club submits this single Consolidated Opposition addressing the five briefs[1] for the convenience of the Board and the parties.

Introduction

Proponents have described much of the procedural background of this matter in their motions, and Sierra Club will not repeat this history except to address factual or legal inaccuracies. Proponents have submitted motions for judgment on the pleadings regarding three claims in Sierra Club's Requests for Agency Action[2] challenging the Approval Orders (AOs) that DAQ issued to IPSC and SPC. In each of their briefs, Proponents challenge two of Sierra Club's claims which are common to both matters: that (1) DAQ is required to consider adequately the Integrated Gasification Combined Cycle (IGCC) production process for generating electricity from coal as part of its "best available control technology" (BACT) analysis for each plant,[3] and (2) that DAQ is

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[1] This Consolidated Opposition refers to the five briefs as:

- "DAQ MJP Brief in SPC" (Executive Secretary's Motion for Judgment on the Pleadings in the Matter of Sevier Power Company Power Plant, DAQE-AN2529001-04);
- "SPC MJP Brief" (Sevier Power Company's Memorandum in Support of Motion for Partial Judgment on the Pleadings);
- "PacifiCorp MJP Brief" (PacifiCorp's Motion for Judgment on the Pleadings);
- "DAQ MJP Brief in IPSC" (Executive Secretary's Motion for Judgment on the Pleadings in the Matter of Unit 3, Intermountain Power Service, DAQE-AN327010-04);
- "IPSC MJP Brief" (Memorandum in Support of IPSC's Motion for Partial Judgment on the Pleadings: Appeal Issues 1, 3, & 5).

[2] For purposes of this Consolidated Opposition, and to make citation easier, "Requests for Agency Action" refers to the Request for Agency Action dated November 12, 2004, submitted in the SPC matter and the First Amended Request for Agency Action dated November 15, 2006 submitted in the IPSC matter. The Proponents' motions for judgment on the pleadings do not concern Sierra Club's pending motions to further amend its pleadings.

[3] Sierra Club IPSC First Amended Request For Agency Action, Statement of Reasons # 1, Sierra Club SPC Request for Agency Action, Statement of Reasons # 2. Exhibit 1, AR IPSC 4494-95, SPC RFA p. 4. The relevant parts of Sierra Club's Requests for Agency

required to address carbon dioxide (CO_2), nitrous oxide (N_2O), and other greenhouse gas emissions during the permitting process, including its BACT analysis.[4] Although Proponents offer different rationales for their motions, all the motions are for a judgment on the pleadings, and the briefs are sufficiently common that Sierra Club can respond to them in a single, consolidated opposition. Because the Executive Secretary is the principal respondent in both matters, this Consolidated Opposition primarily focuses on Executive Secretary's arguments, and addresses the other Proponents' arguments as appropriate and necessary.[5]

The Board should deny Proponents' motions for judgment on the pleadings because Sierra Club's pleadings sufficiently state claims on which the Board could grant relief. Motions for judgment on the pleadings, offered early in the proceedings, address only the sufficiency of Sierra Club's pleadings. "Pleadings" is a term in the Utah Rules of Civil Procedure that, in a court case, means the complaint and the answer[6] – in these administrative proceedings, "pleadings" corresponds to Sierra Club's Requests for

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Action are attached as Exhibit 1, and materials incorporated by reference in those sections are provided on the enclosed CD-Rom.

[4] Sierra Club IPSC First Amended Request For Agency Action, Statement of Reasons # 3, Sierra Club SPC Request for Agency Action, Statement of Reasons # 1. Exhibit 1, AR IPSC 4496-97, SPC RFA pp. 3-4.

[5] IPSC alone has filed a motion for judgment on the pleadings regarding a separate issue – Sierra Club's claim that DAQ erroneously issued the permit for Unit 3 without adequate coal chemistry data. Exhibit 1, AR IPSC 4498. That issue is also addressed in this Consolidated Opposition.

[6] Utah R. Civ. P. 7(a) ("Pleadings. There shall be a complaint and an answer; a reply to a counterclaim; an answer to a cross claim, if the answer contains a cross claim; a third party complaint, if a person who was not an original party is summoned under the provisions of Rule 14; and a third party answer, if a third party complaint is served. No other pleading shall be allowed, except that the court may order a reply to an answer or a third party answer.")

Agency Action in each matter, including the documents incorporated in them by reference, along with the responses to the Requests for Agency Action.

This means that the Board reviews only Sierra Club's Requests for Agency Action to decide whether Sierra Club has adequately alleged claims on which relief could be granted. A motion for judgment on the pleadings does not address the ultimate merits of those claims. As will be clear from the applicable legal standards for deciding a motion for judgment on the pleadings, discussed below, the Board must accept as true all the facts that Sierra Club alleges for purposes of these preliminary motions.

Sierra Club regrets that a significant part of this brief is devoted to describing the correct legal standards and procedure the Board must follow in deciding these motions. This is due, in part, to the fact that the standards for deciding motions made at different points throughout the course of a case vary according to how much evidence has been developed up to that point, and, in particular, whether there has been a hearing. It is also due, in part, to the need to describe fully the legal standards which apply to <u>these</u> motions for judgment on the pleadings, which are not described in sufficient detail in Proponents' briefs.

In addition, despite the fact these are motions "on the pleadings," none of the Proponents has actually attached Sierra Club's pleadings to their motions or briefs. It means that the Board has had to review Proponents' briefs without the benefit of having the actual pleadings before it, and has required this Consolidated Opposition to be longer than it might otherwise have needed to be. In addition, as described below at pages 41-44, Proponents have introduced procedural confusion by presenting "motions for

judgment on the pleadings" and attaching materials that are not part of the pleadings, necessitating a response and clarification from Sierra Club.

To decide a motion for judgment on the pleadings, the Board must take all of Sierra Club's factual allegations in its Requests for Agency Action (RFA) as true. At this stage, the Board cannot weigh competing arguments regarding the facts – rather, the Board has to take Sierra Club's facts as true, and may only grant the motions if the Board determines that there is no set of facts that Sierra Club could prove to support its claim. When the Board accepts the facts in Sierra Club's pleadings as true, and analyzes them in conjunction with the applicable law, the Board must deny the motions for judgment on the pleadings because it is clear that Sierra Club has sufficiently alleged its claims.

I. The Board Must Apply the Correct Legal Standards for Deciding Motions for Judgment on the Pleadings.

A. In Ruling on the Motions for Judgment on the Pleadings, the Board Must Accept Sierra Club's Factual Allegations as True.

None of the Proponents correctly describes the legal standards the Board must apply in deciding whether to grant or deny the motions for judgment on the pleadings. In addition, they do not cite the principal Utah cases addressing motions for judgment on the pleadings. The Executive Secretary comes closest, providing the language of Utah Rule of Civil Procedure 12(c), which covers motions for judgment on the pleadings: "After the pleadings are closed but within such time as not to delay the trial, any party may move for judgment on the pleadings."[7] The Executive Secretary is also correct that "a grant of a motion for judgment on the pleadings is reviewed under the same standard as the grant

[7] Utah R. Civ. P. 12(c).

of a motion to dismiss."[8] However, the most important standard the Board must apply in deciding a motion for judgment on the pleadings is missing from all of Proponents' briefs: this is that, in deciding a motion for judgment on the pleadings, the Board must assume the truth of the allegations in Sierra Club's Requests for Agency Action, including the documents which those Requests incorporate by reference.[9]

The Utah Supreme Court has stated that "dismissal[10] is a severe measure and should be granted by the [Board] only if it is clear that a party is not entitled to relief under any state of facts which could be proved in support of its claim."[11] Furthermore, when deciding a motion for judgment on the pleadings, the Court has made clear that the only "issue before the [Board] is whether the petitioner has alleged enough in the complaint to state a cause of action,"[12] and that a motion for judgment on the pleadings "concerns the sufficiency of the pleadings, not the underlying merits of a particular case."[13] In deciding these motions, the Board will "look solely to the material allegations of [the plaintiff's] complaint."[14]

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[8] Golding v. Ashley Cent. Irr. Co., 793 P.2d 897, 898 (Utah 1990); see DAQ MJP Brief in SPC at 2, DAQ MJP Brief in IPSC at 2.

[9] Golding, 793 P.2d at 898 ("in considering the factual allegations in the complaint, we take them as true and consider them and all reasonable inferences drawn therefrom in a light most favorable to the plaintiff."); Colman v. Utah Land Bd., 795 P.2d 622, 624 (Utah 1990) (the court may "look solely to the material allegations of [the plaintiff's] complaint").

[10] The Supreme Court is discussing a motion to dismiss in this case. However, as the Executive Secretary points out, the courts will treat a motion for judgment on the pleadings in the same way as a motion to dismiss.

[11] Colman., 795 P.2d at 624 (emphasis added). In these proceedings, the Board is in the same position as a trial court because it is "vested with adjudicative functions," Utah Chapter of the Sierra Club v. Air Quality Bd., 2006 UT 74, ¶ 12, 148 P.3d 960, and thus "Board" replaces "trial court" in the description of the legal standards.

[12] Alvarez v. Galetka, 933 P.2d 987, 989 (Utah 1997) (emphasis added).

[13] Id.

[14] Colman, 795 P.2d at 624.

Most importantly, in deciding whether to grant or deny a motion on the pleadings, the Board must "take the factual allegations of the nonmoving party [Sierra Club] as true, considering such facts 'and all reasonable inferences drawn therefrom in a light most favorable to the [nonmoving party – Sierra Club].'"[15] The Board may grant the motions only "if, as a matter of law, the plaintiff could not recover under the facts alleged."[16]

Under the applicable Utah legal standards, a court (or, in this instance, the Board) should be reluctant to grant a motion for judgment on the pleadings because the Board is "a forum for settling controversies, and if there is any doubt about whether a claim should be dismissed for the lack of a factual basis, the issue should be resolved in favor of giving the party an opportunity to present its proof."[17] The Board should be aware that "judgments on the pleadings are 'not favored by the courts, and when made[,] great liberality in construing the assailed pleading should be allowed.'"[18]

One further point: Utah law is also clear that, when deciding the motions for judgment on the pleadings, the Board may only consider the materials in the pleadings, and no material outside of the pleadings.[19] The pleadings consist of "complaints and answers" allowed under Utah Rule of Civil Procedure 7(a).[20] Pleadings also include

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[15] Straley v. Halliday, 2000 UT App 38, ¶ 2, 997 P.2d 338) (quoting Golding, 793 P.2d at 898)
[16] Golding, 793 P.2d at 898.
[17] Colman, 795 P.2d at 624 (emphasis added); see also Celebrity Club, Inc. v. Utah Liquor Control Comm'n, 657 P.2d 1293, 1296 (Utah 1982) ("It has always been the policy of our law to resolve doubts in favor of permitting parties to have their day in court on the merits of a controversy." (footnote and quotations omitted)).
[18] MBNA America Bank, N.A. v. Williams, 2006 UT App 432, ¶ 2, 147 P.3d 536 (quoting Harman v. Yeager, 110 P.2d 352, 353 (Utah 1941)).
[19] Colman 795 P.2d at 624, Oakwood Village LLC v. Albertson's Inc., 2004 UT 101, ¶15, 104 P.3d 1226.
[20] Tuttle, 2007 UT App 10, ¶ 9.

materials incorporated by reference in the pleadings.[21] In this case, Sierra Club's Requests for Agency Action incorporate by reference four sets of comments Sierra Club submitted to the DAQ.[22] As a result, these comments are part of the pleadings for purposes of these motions.

Although motions for judgment on the pleadings must be based on the pleadings, it is rather odd that none of the Proponents have attached any of the pleadings to their briefs. To rectify this omission – and because Proponents have in places selectively quoted or inaccurately characterized Sierra Club's claims – Sierra Club attaches as Exhibit 1 the relevant sections of its Requests for Agency Action. In addition, because those relevant sections incorporate by reference the eight sets of comments (including supporting documents) that Sierra Club submitted to DAQ in 2003 and 2004, Sierra Club encloses a CD-Rom for the Board's review which contains those comments.[23] Because Sierra Club's pleadings thus amount to more than 2,000 pages of materials, Sierra Club

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[21] Oakwood Village, 2004 UT 101, ¶ 13 (holding that material formally incorporated by reference in a complaint is a matter within the pleadings); see also id. ¶ 14-15 (holding that a declaration that was "central to and referenced in the complaint" was "material within the pleadings.").

[22] Sierra Club's Request for Agency Action in the IPSC matter expressly states that it (and the Grand Canyon Trust) "hereby incorporate and reference their comments dated April 14, 2003, May 20, 2004, June 30, 2004, and July 16, 2004, and the documents submitted in support of those comments." Exhibit 1, AR IPSC 4494. Similar language appears in the Request for Agency Action in the SPC matter. Exhibit 1, SPC RFA p. 3. In addition, the Sierra Club expressly noted that "The Sierra Club and Grand Canyon Trust have, in their May 20, 2004 comments on the ITA for the IPP project, detailed the basis for this and other statements regarding the need to evaluate IGCC as part of a proper BACT analysis for IPP. Because the organizations have already referenced and incorporated those comments into their Request for Agency Action, they will not repeat those detailed arguments here." Exhibit 1, AR IPSC 4494, footnote 3.

[23] These comments and supporting documents appear in the Administrative Records at AR IPSC 1377-1529, AR IPSC 2349-3356, AR IPSC 3547-3714, AR IPSC 3776-3872, and among the public comments in the compilation provided by the Executive Secretary numbered "AR SPC 1131."

will provide the Board with selected pages from among those pleadings in hard copy for its convenience in reading this brief, attached as Exhibit 2. However, because the comments on enclosed CD-Rom are an integral part of Sierra Club's pleadings, the Board should consider the facts described in them as true in deciding these motions for judgment on the pleadings.[24]

B. The "Burden of Proof" on a Motion for Judgment on the Pleadings Rests on the Moving Parties – the Executive Secretary, IPSC, SPC, and PacifiCorp.

The Executive Secretary has correctly advised the Board in its briefs that, on these motions, the burden is on the "moving party" or parties – that is, on the Executive Secretary, IPSC, SPC, and PacifiCorp – to "'clearly establish that no material issue of fact remains to be resolved and that [they are] entitled to judgment as a matter of law."[25] The Harken case that IPSC and PacifiCorp cite[26] involved a Board of Oil, Gas & Mining decision on the merits, after that Board received extensive testimony – not a motion for judgment on the pleadings.[27] Unlike in Harken, the burden rests on Proponents at this stage in the proceedings. Indeed, IPSC and PacifiCorp's incorrect statement of the applicable law on these motions would "prematurely shift[] the burden of proof to the plaintiff and in effect relieve[] the defendant[s] from [their] burden of proof."[28] Because the Utah Supreme Court has clearly laid out how the Board must evaluate the facts and

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[24] In the event the Board grants the Proponents' motions, the comments on the enclosed CD-Rom will also constitute part of the record on appeal.
[25] DAQ MJP Brief in SPC at 2, DAQ MJP Brief in IPSC at 2.
[26] IPSC MJP Brief at 5, PacifiCorp MJP Brief at 2.
[27] Harken S.W. Corp. v. Bd. of Oil, Gas & Mining, 920 P.2d 1176, 1180-83 (Utah 1996) (describing the expert testimony the Board of Oil, Gas & Mining heard in that case before rendering its decisions).
[28] Zoumadakis v. Uintah Basin Medical Center, Inc., 2005 UT App 325, ¶ 6 n.4, 122 P.3d 891.

consider the motions for judgment on the pleadings, the arguments by IPSC and PacifiCorp regarding "burden of proof" are flatly wrong for purposes of these motions.

Furthermore, on the ultimate underlying question of the adequacy of DAQ's evaluation of IGCC as BACT on the merits, it is the applicants – IPSC and SPC – that bear the burden of proof.[29] Federal courts and the U.S. Environmental Protection Agency (EPA) Environmental Appeals Board (EAB) have repeatedly confirmed that the BACT "top-down approach places the burden of proof on the applicant to justify why the proposed source is unable to apply the best technology available,"[30] and that "permit applicants must apply the most stringent control alternative, unless the applicant can demonstrate that the alternative is not technically or economically achievable.").[31] Thus, on the merits of Sierra Club's claims, the applicants IPSC and SPC must show that they demonstrated to DAQ the infeasibility or non-achievability of IGCC as the best available control technology – and the Board must evaluate whether DAQ's ultimate determination was correct.

In any case, the Board's decision on these motions for judgment on the pleadings is not about Sierra Club's claims on the merits – the Board will decide the merits later in these proceedings, after hearing all the evidence in these cases. Instead, the standard applicable to these motions for judgment on the pleadings requires that the Board accept

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[29] Although IPSC has alluded to the adequacy of the IGCC "analysis" it submitted to DAQ, IPSC MJP Brief at 12, the question of the adequacy of that analysis is not before the Board on these motions for judgment on the pleadings. Sierra Club has adequately pled that DAQ's review of that IPSC submission was inadequate and improper. See Exhibit 1, AR IPSC 4495.

[30] Citizens for Clean Air v. EPA, 959 F.2d 839, 845 (9th Cir. 1992) (emphasis added); In re Pennsauken County, New Jersey Resource Recovery Facility, PSD Appeal No. 88-8 (EAB Nov. 10, 1988) (same holding).

[31] In re Inter-Power of New York, Inc., 5 E.A.D. 130, 135 (EAB 1994) (emphasis added).

everything Sierra Club has alleged as true – and, under this standard, any issue of burden of proof which might be applicable at after the Board has heard all the testimony on the merits evidently does not apply at this early stage in the proceedings.

C. The Board May Properly Consider Facts and Legal Arguments that Have Arisen Since the DAQ Decision.

IPSC alone makes the argument[32] that the Board should not consider legal arguments based on facts that have arisen since the DAQ made its decision to issue the Approval Order (AO). This argument is incorrect. Indeed, IPSC directly contradicts its own argument by offering the Board several citations in its brief to facts that occurred as late as November 29, 2006.

First, IPSC expressly contradicts its own argument by citing to at least four factual incidents that occurred after its AO was approved in October 2004. On pages 8-9 of its brief, IPSC cites the November 29, 2006 Supreme Court oral argument by EPA's counsel. On page 9, IPSC cites a February 27, 2006 Federal Register notice. On page 11, in footnote 9, IPSC cites a magazine article from November 2006. On page 14, IPSC cites an EPA letter dated December 13, 2005. IPSC's liberal reliance on post-October 2004 facts and legal developments clearly demonstrates the fallacy of its own argument that the Board should be locked rigidly into considering absolutely nothing that has happened since DAQ approved its AO.

Second, many of Sierra Club's claims rest on the Board's ultimate conclusions as to what the law <u>is</u> – and it is a "long-standing traditional rule" that evolving legal

[32] IPSC MJP Brief at 6-7.

decisions and principles must be applied to cases that are currently pending on appeal.[33] As the Utah Supreme Court has noted, "'[i]t is well established that when a lower court relies on a legal principle which is changed by treaty, statute, or decision prior to direct review, an appellate court must apply the current law rather than the law as it existed at the time the lower court acted.'"[34] The Board stands in the place of an appellate court in these matters: DAQ is an executive agency acting in an administrative capacity, and its legal decisions are not binding or final.[35] The Board, charged with the power to review DAQ decisions, also has the responsibility to determine what the law requires. And, in reviewing these DAQ decisions, the Board has an obligation to consider how the law has developed over the past two-and-a-half years. Sierra Club does agree that, to the extent any of its claims address the adequacy of DAQ's application of any legal principle that was clearly established at the time of DAQ's review, the Board's review is limited to the factual information the agency had before it when it made its decision.

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[33] State v. Saunders, 1999 UT 59, ¶ 53, 992 P.2d 951 (holding that a new court decision would be applied both prospectively and retrospectively).

[34] State v. Belgard, 615 P.2d 1274, 1276 (Utah 1980) (quoting United States v. Fitzgerald, 545 F.2d 578 (7th Cir. 1976)).

[35] The Executive Secretary may only act ""as authorized by the board." Utah Code Ann. §19-2-107(2)(g)(2). See also Green River Canal Co. v. Thayn, 2003 UT 50, ¶ 30, 84 P.3d 1134 ("[t]he State Engineer is an executive, not a judicial officer," … and the State Engineer's decisions are not binding on the courts of this state. The State Engineer acts in an administrative capacity") (citations omitted).

II. The Board Must Deny the Motions for Judgment on the Pleadings Because Sierra Club's Requests for Agency Action Sufficiently State Claims on Which Relief Can Be Granted.

A. The Board Must Deny the Motions for Judgment on the Pleadings on Sierra Club's Claims Regarding the Integrated Gasification Combined Cycle (IGCC) Production Process (IPSC RFA # 1, SPC RFA # 2) Because, Taking as True Sierra Club's Factual Allegations, Sierra Club Has Stated a Claim on Which Relief Can Be Granted.

Proponents rely only on characterizations of Sierra Club's pleadings, but have not provided the full text of Sierra Club's claims in their briefs, nor attached the pleadings to their briefs. Sierra Club refers the Board to Exhibit 1, which contains – in full – the sections of Sierra Club's Requests for Agency Action at issue in these motions. In both of Sierra Club's Requests for Agency Action, its claim relating to Integrated Gasification Combined Cycle (IGCC) technology is that "DAQ is required to evaluate this technology comprehensively as part of its BACT analysis."[36] IGCC is significant because it is a proven, currently-available production process for converting coal to energy that also best fulfills the Clean Air Act's overarching goal of reducing pollution emissions.[37] IGCC provides significant reductions in the emission of criteria and hazardous air pollutants compared to the boiler technologies that IPSC and SPC have proposed, provides the opportunity for capturing carbon dioxide and other greenhouse gases, and provides a general increase in efficiency over other technologies.[38] Because of these pollution reduction benefits, DAQ is required to evaluate IGCC as part of its BACT analyses.

Sierra Club has alleged in its Request for Agency Action that IGCC is "an available, demonstrated, clean coal combustion technology with significant emission

[36] Exhibit 1, AR IPSC 4494, SPC RFA p. 4.
[37] Exhibit 2, AR IPSC 2351, AR SPC 2308.
[38] Exhibit 2, AR IPSC 2351, AR SPC 2308.

reduction benefits" that is "technically feasible for the [two projects], and is the top ranked control technology."[39] By express reference, Sierra Club has also alleged that IGCC is a "production process," an "available method" of reducing pollution emissions from plants that convert coal to electricity, and an "innovative fuel combustion technology."[40] Taking these allegations as true, and drawing all inferences in favor of Sierra Club, it is clear that IGCC comes within the definition of BACT, and therefore that Sierra Club has adequately stated a claim. The Board therefore must deny Proponents' motions on this issue.

1. Based on the Facts Alleged in Sierra Club's Requests for Agency Action, IGCC Falls Within the Definition of BACT in the Clean Air Act and the Utah Air Quality Regulations.

The Clean Air Act requires that "no major emitting facility … may be constructed in any area to which this part applies unless … the facility is subject to the best available control technology for each pollutant subject to regulation under this chapter emitted from, or which results from, such facility."[41] The Utah air quality regulations define "best available control technology" as:

> [A]n emission limitation and/or other controls to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree of reduction of each pollutant subject to regulation under the Clean Air Act and/or Utah Air Conservation Act emitted from or which results from any emitting installation, which the Air Quality Board, on a case-by-case basis taking into account energy, environmental and economic impacts and other costs, determines is achievable for such installation through the application of production processes and available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant.[42]

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[39] Exhibit 1, AR IPSC 4494-95, SPC RFA p. 4.
[40] Exhibit 2, AR IPSC 2352, 2354, 2356, AR SPC 2000, 2312-14.
[41] 42 U.S.C. §7475(a)(4).
[42] Utah Admin. Code R307-101-2. The BACT definition has been amended and renumbered as Utah Admin. Code R307-401-2, with the significant change that the

None of the underlined terms in the BACT definition are further defined by Utah law or regulation. The Executive Secretary and the other Proponents emphasize the BACT regulation differently in their briefs. The fact that the parties choose to emphasize different parts of the definition demonstrates clearly the deep factual divide between their positions. However, the applicable legal standards do not allow the Board to determine, at this time, without careful consideration of the relevant facts regarding the IGCC process, which parties' position is ultimately correct. Instead, to decide these motions for judgment on the pleadings, the Board must take the following facts alleged in Sierra Club's pleadings (and the documents incorporated by reference) as true, and disregard any contrary factual statements made in Proponents briefing:

1. IGCC is a method of producing electricity by gasifying the coal, removing pollutants – including greenhouse gases – before combustion, and then burning the "clean" syngas in a modified combined cycle gas-fired power plant. Exhibit 1, AR IPSC 4494, SPC RFA p. 4.
2. IGCC is an available technology for producing electricity from coal. Exhibit 1, AR IPSC 4495), SPC RFA p. 4; Exhibit 2, AR IPSC 1382-83, AR SPC 1245.
3. IGCC is technically feasible for the IPSC and SPC projects. Exhibit 1 at 4495; Exhibit 2, AR SPC 1247.
4. IGCC is the top ranked control technology. Exhibit 1, AR IPSC 4495; Exhibit 2, AR IPSC 1383-85, AR SPC 1247-49.

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former term "installation" has now been replaced with "proposed stationary source." The significance of this change is discussed below in footnotes 49-51 and the accompanying text.

5. IGCC is an available, demonstrated clean coal combustion technology with significant emission reduction benefits. Exhibit 2, AR IPSC 2351, AR SPC 1240.
6. IGCC is a production process that can be used to produce electricity from coal. Exhibit 2, AR IPSC 1381, AR SPC 1244.
7. IGCC is a method for generating electricity from the combustion of coal. Exhibit 2, AR IPSC 1381, AR SPC 1244.
8. IGCC is an innovative fuel combustion technique, and Congress intended that coal gasification be included among the "innovative fuel combustion techniques" considered in BACT analyses. Exhibit 2, AR IPSC 2352; AR SPC 2000, 2309.
9. Requiring consideration of IGCC would not be redefining the source. Exhibit 1, AR IPSC 4495, SPC RFA p. 4.

Applying these facts, taken as true, to the regulatory definition of BACT shows clearly that IGCC comes within the definition of BACT. First, "best available control technology" is an "emissions limitation" that achieves the maximum reduction of each pollutant that is "achievable" <u>by applying</u> "production processes" and "available methods" – which include "fuel cleaning or treatment" as well as "innovative fuel combustion techniques."[43] As alleged in Sierra Club's pleadings, IGCC achieves maximum emission reductions as a "production process" for generating electricity from

[43] 42 U.S.C. §7475(a)(4); Utah Admin. Code R307-101-2. The Executive Secretary's discussion of the BACT rule essentially ignores all of the language in the rule following "through the application of." DAQ MJP Brief in SPC at 11, DAQ MJP Brief in IPSC at 11.

coal;[44] it is an "available method" for generating electricity from coal;[45] it is an "innovative fuel combustion technique," and it is therefore squarely within Utah's definition of "best available control technology."[46] On a plain reading of the BACT rule, IGCC must be considered as part of the BACT analysis. Because IGCC comes within the definition of BACT, DAQ was required to include "emissions limitations" in the IPSC Unit 3 and SPC permits based on the application of IGCC – emissions limitations that would be equivalent to a coal-fired power plant equipped with IGCC technology. Such emissions limitations would result in significant reductions in pollution from the proposed plants.

2. "Best Available Control Technology" is Not Limited to the Technology Proposed by the Applicant.

The Executive Secretary's argument that "the BACT analysis includes control technologies that can be applied to an installation that has already been identified" is incorrect.[47] In effect, the Executive Secretary's proposed interpretation of "installation" would obliterate the BACT analysis, because once an "installation" has been identified in the notice of intent, no changes could be made to it based on the "application of production processes and available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques" that BACT regulation requires.[48] Thus, the Executive Secretary's approach would make meaningless the core requirements of BACT – that achievable emission limitations must reflect the application of production processes, available methods, and systems and techniques for the control of

[44] Exhibit 1, AR IPSC 4494, SPC RFA p. 4; Exhibit 2, AR IPSC 1381, AR SPC 1244.
[45] Exhibit 2, AR IPSC 2351, AR SPC 1240.
[46] Utah Admin. Code R307-101-2.
[47] DAQ MJP Brief in SPC at 11, DAQ MJP Brief in IPSC at 11.
[48] Utah Admin. Code R307-101-2.

pollutants. Indeed, under the Executive Secretary's reading of BACT an applicant could identify a completely antiquated installation in its notice of intent and neither he nor DAQ would have the authority to require the applicant to modernize that identified installation. Thus, the technology-forcing intent of BACT would be totally lost and the provision would cease to achieve maximum reductions in pollutants. Plainly, Utah and federal definitions of BACT clearly contemplate far more than the end-of-the-tailpipe control technologies suggested by the Executive Secretary's argument.[49]

In any case, the Executive Secretary's narrow approach to BACT conflicts with the federal definition of BACT, and therefore must be rejected.[50] In administering a program under the Clean Air Act, DAQ may not adopt a standard that directly conflicts with the federal definitions of the same term, because state implementation plans (SIPs) must be consistent with federal PSD regulations.[51] In no way does the federal regulation suggest that, in applying the BACT analysis, an agency must accept as unalterable a "discrete" installation or an already "identified" installation. Rather, the federal definition, like the Utah definition, gives meaning to maximum pollution reduction by not accepting as a given any particular installation or source, but by requiring the emission limitations that maximize reduction of air pollutants and are achievable by applying

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[49] If it were interpreted as the Executive Secretary suggests, the Utah BACT definition would also impermissibly conflict with the federal definitions, because the federal definitions of BACT do not include the term "installation." Instead, the Clean Air Act speaks of emissions from a "major emitting facility," 42 U.S.C. § 7479(3), while EPA regulations speak of "any proposed major stationary source." 40 C.F.R. § 52.21(b)(12).

[50] See footnote 49.

[51] The SIP requirements provide that "[a]ll State plans shall use the following definitions for the purposes of this section. Deviations from the following wording will be approved only if the State specifically demonstrates that the submitted definition is more stringent, or at least as stringent, in all respects" as the federal definitions." 40 C.F.R. §51.166(b) (emphasis added).

production processes, and available methods, systems and techniques, including "innovative fuel combustion techniques."[52] That this is the proper understanding of BACT is further underscored by the discussion below.

3. Because IGCC is a Production Process, an Available Method for Reducing Pollution from Plants Generating Electricity from Coal, and an Innovative Fuel Combustion Technique, it Comes Within the Definition of BACT.

Taking Sierra Club's factual allegations as true for purposes of these motions, as the Board must, Sierra Club has clearly stated a claim that the IGCC production process comes within the definition of BACT, and thus that DAQ had an obligation to consider it as the basis for establishing emission limits on the proposed plants. From the statements in Proponents' briefs,[53] it is evident that they disagree with the factual characterizations of what IGCC is. However, the Board has not yet received any evidence, expert testimony, or description of the IGCC process on which it can base a legal conclusion regarding that process. Because the Executive Secretary and the other Proponents dispute the factual nature of IGCC,[54] the Board must deny their motions for judgment on the pleadings and allow this issue to proceed to discovery and a hearing.

In addition, Proponents' legal arguments regarding IGCC and BACT are incorrect. First, the Utah air quality regulations do not define terms such as "production

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[52] In this respect, it is telling that this Board has since changed the definition of BACT to eliminate the term "installation," and instead now refers to emissions "from any proposed stationary source." Utah Admin. Code R307-401-2.

[53] For example, the Executive Secretary has stated that IGCC is not a control technology, DAQ MJP Brief in SPC at 4, DAQ MJP Brief in IPSC at 3; IPSC has stated that IGCC is "unproven," IPSC MJP Brief at 13; and all Proponents have argued that IGCC would constitute "redefining the source." Sierra Club alleges that IGCC is a control technology, that it is an available and demonstrated process, and that consideration of IGCC would not involve redefining the source. See pages 15-16, above.

[54] For example, IPSC argues that IGCC is "unproven under the conditions required for Unit 3." IPSC MJP Brief at 13.

process" or "innovative fuel technology," and there is no guidance in the Utah Air Conservation Act or reported Utah case law that keeps the Board from requiring that DAQ consider IGCC as part of a BACT analysis. Thus the Board, in these adjudications, will ultimately determine the legal meaning of those terms. Second, IGCC is quintessentially the sort of production process meant to be considered in a BACT analysis. EPA has repeatedly acknowledged that the PSD program is technology-forcing and intended to become more stringent over time as control technologies improve and new cleaner processes are introduced. For example, the Environmental Appeals Board has explained that:

> A major goal of the CAA was to create a program that was technology forcing. . . . "The Clean Air Amendments were enacted to 'speed up, expand, and intensify the war against air pollution in the United States with a view to assuring that the air we breathe throughout the Nation is wholesome once again.'" . . . .
>
> In keeping with this objective, the program Congress established was particularly aggressive in its pursuit of state-of-the-art technology at newly constructed sources. At these sources, pollution control methods could be efficiently and cost-effectively engineered into plants at the time of construction. [55]

Indeed, the legislative history of the 1977 amendment adding the term "innovative fuel combustion techniques" to the Clean Air Act's definition of "BACT" makes clear that BACT includes coal gasification technology such as IGCC. The amendment's sponsor, Senator Huddleston, declared that "[i]t is the purpose of this amendment to leave no doubt that in determining best available control technology, <u>all</u> actions taken by the fuel user are to be taken into account – <u>be they the purchasing or production of fuels</u>

[55] <u>In Re Tenn. Valley Auth.</u>, 9 E.A.D. 357, 391 (EAB 2000) (<u>citing</u> <u>Wisc. Elec. Power Co. v. Reilly</u>, 893 F.2d 901, 909 (7th Cir 1990) and H.R. Rep. No. 95-294, at 185, <u>reprinted in</u> 1977 U.S.C.C.A.N. at 1264).

which may have been cleaned or up-graded through chemical treatment, gasification, or liquefaction ….”[56] Senator Huddleston expressly noted that “the concept of BACT is intended to include such technologies as low Btu gasification and fluidized bed combustion. But, this intention is not explicitly spelled out, and I am concerned that without clarification, the possibility of misinterpretation would remain. It is the purpose of this amendment [adding the term “innovative fuel combustion techniques”] to leave no doubt that” a coal gasification process like IGCC comes within BACT.[57]

Both the language of the Clean Air Act itself and the unequivocal expressions of congressional intent in the legislative history indicate, that in order to fully comply with the Act, the emission limits identified as BACT must incorporate consideration of more than just add-on emission control technology – they must also reflect appropriate considerations of fuel quality (such as low sulfur coal) and processes capable of reducing emission (including, specifically, innovative combustion techniques such as coal gasification). Indeed, this requirement is not only consistent with, but necessary to the very core objective of PSD permitting – to bring about the rapid adoption of cleaner technologies that provide for a greater reduction in regulated emissions.[58]

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[56] Arnold & Porter, 123 Cong. Record S9421, Clean Air Act Amendments of 1977 (June 10, 1977) (Statement of Sen. Huddleston) (emphasis added).
[57] Id. (emphasis added).
[58] Emission controls under the CAA are universally recognized as including process changes (including inherently cleaner processes) as well as add-on control technology. The PSD provisions expressly recognize this in the definition of BACT included in section 169 of the Act, 42 U.S.C. § 7479. Other sections of the Act reinforce the fact that Congress generally understood and accepted that emission control is often most effectively achieved through process changes. See 42 U.S.C.§ 7412(d)(2) (identifying mechanisms for reducing emission of hazardous air pollutants as including, in addition to add-on controls, “process changes, substitutions of materials or other modifications,” as well as “design, equipment, work practice, or operational standards”).

4. IGCC is Widely Accepted as a Component of a Proper BACT Analysis.

In recent PSD permitting actions implementing the federal PSD permitting program (either through a direct delegation from EPA or via approval of equivalent state rules in a state implementation plan (SIP)), several states have required consideration of IGCC in the BACT review process for new power plants which generate electricity from coal. These state decisions implementing the federal PSD program validate the plain language of the definition of BACT described above. It is important to note that, while some of these states were operating under SIP-approved PSD programs, the definition of BACT that applied in all cases is virtually identical to the federal definition of BACT with respect to consideration of inherently lower emitting processes. It is noteworthy that these states determined it was entirely appropriate to require consideration of IGCC in the BACT review for a coal- fired power plant.

- In March 2003, the State of Illinois required the applicant for a proposed CFB coal-fired electric generation facility to conduct a robust analysis of IGCC as a core element of its BACT analysis.[59] In an ensuing letter, the State of Illinois then formally informed EPA that Illinois has "concluded that it is appropriate for applicants for [proposed coal- fired power plants] to consider IGCC as part of their BACT demonstrations."[60]

- In December 2002, the State of New Mexico issued a letter requiring a permit applicant for a new coal- fired power plant to conduct a site-specific analysis of IGCC as part of the BACT analysis for the proposed facility.[61] In its evaluation of the applicant's response, New Mexico found that the applicant's BACT analysis had in fact indicated that IGCC is commercially available but that the

[59] Exhibit 2, AR IPSC 2355, 2840, AR SPC 2199, 2312 (Letter from Illinois Division of Air Pollution Control to Jim Schneider, Indeck-Elwood, LLC (March 8, 2003)).
[60] Exhibit 2, AR IPSC 2355, AR SPC 2312 (Letter from Illinois EPA Director to EPA Regional Administrator, Region V (March 19, 2003)).
[61] Exhibit 2, AR IPSC 2355, AR SPC 2313 (Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Corporation (Dec. 23, 2002)).

applicant had improperly relied on cost to find that the technology was infeasible.[62]

- In addition, the Montana Board of Environmental Review found that the Montana Department of Environmental Quality must consider IGCC as an available technology in the BACT review for a coal-fired power plant, stating ". . . the Department should require applicants to consider innovative fuel combustion techniques in their BACT analysis and the Department should evaluate such techniques in its BACT determination in accordance with the top-down five-step method."[63]

Illinois and Montana are notable because they are the very states which found IGCC to be both a "production process" and an "innovative fuel combustion technique" for achieving greater reductions in pollution emission at a coal-fired generating facility, and therefore, as a matter of law, to be required as part of a BACT analysis.[64]

5. Requiring IGCC as Part of a BACT Analysis Does Not Involve Redefining the Source and Does Not Conflict With Utah's Restriction on Regulating More Stringently Than the Federal Government.

Although Proponents offer a description of EPA guidance on the question, they do not cite any Utah or federal law or regulation that includes the term "redefining the source." However, the plain language of the BACT regulation includes terms such as "production process" and "innovative fuel combustion technology" that describe what IGCC is. Whether IGCC truly is "redefining the source" cannot be decided simply by reviewing Sierra Club's pleadings, when the Board must take as true Sierra Club's factual allegations that IGCC is a production process, available method, and innovating fuel combustion technology. Rather, the Board will have to consider relevant facts – how

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[62] Exhibit 2, AR IPSC 2356, AR SPC 2314 (Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Company (Aug. 29, 2003)).
[63] Exhibit 2, AR IPSC 2356, AR SPC 2000 (Montana Board of Environmental Review, Findings of Fact, Conclusions of Law, and Order In the Matter of the Air Quality Permit for the Roundup Power Project (Permit No, 3182-00), Case No. 2003-04 AQ (June 23, 2003)).
[64] See Exhibit 2, AR IPSC 2355-56, AR SPC 2000, 2312.

IGCC operates, how it can be integrated into the facility that produces electricity from coal, whether it is available and achievable for these two proposed facilities – in deciding whether requiring emissions limitations based on IGCC as BACT are necessary for the two permits. No factual information, except that alleged in Sierra Club's pleadings, is before the Board at this time.

Moreover, consideration of IGCC technology does not "redefine the source" in a manner that permits the agency to exclude analysis of IGCC from its BACT analysis. Such categorical dismissal of any obligation by DAQ to consider or evaluate the availability, applicability, effectiveness, collateral environmental benefits, or cost effectiveness of a recognized process option for further reducing emission from a power plant producing electricity from coal is flatly contrary to the agency's responsibilities under the PSD program. This argument is inconsistent with the Clean Air Act, the EPA Environmental Appeals Board's (EAB) treatment of the concept of "redefining the source," and decisions by earlier EPA Administrators.

First, as discussed above, Utah's BACT definition, like its federal counterpart, specifically calls for establishing emission limitations based on "the application of <u>production processes</u> and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or <u>innovative fuel combustion techniques</u> for control of each pollutant."[65] This language, on its face, requires as a part of the BACT analysis the consideration of innovative technologies like IGCC that make the generation of electricity from coal significantly cleaner.[66]

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[65] Utah Admin. Code R307-101-2 (emphasis added).

[66] As discussed above at pages 20-21, the legislative history of the CAA is equally as clear that the definition of BACT contemplates consideration of technologies like IGCC.

In the Prairie State decision,[67] EPA's Environmental Appeals Board strongly indicated that IGCC is a control technology that must be considered in the BACT analysis. The EAB specifically assumed that even though "selection of IGCC would have required extensive design changes to the [power plant's] proposed Facility," the permitting agency correctly included IGCC in the facility's BACT analysis, despite the permit-applicant's objection that doing so would violate EPA's "policy against redefining the design of the source through application of BACT."[68] Thus, in light of the EAB's decision, improving pollution control by basing emission limitations on the IGCC production process does not constitute "redefining the source."[69]

EAB's endorsement of IGCC in Prairie State is consistent with EPA's position in its New Source Review Workshop Manual that a permitting authority must consider all inherently lower-emitting processes in its BACT analysis, and that "[l]ower-polluting processes should be considered based on the demonstrations made on the basis of manufacturing identical or similar products from identical or similar raw materials or fuels."[70] IGCC is a production process for generating electricity from coal.[71] As such, IGCC involves the identical raw material – coal – and the identical finished product – electricity – as the generation technology proposed by IPSC and SPC. As a result, relevant EPA authority requires that IGCC be considered as part of a BACT analysis.

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[67] In re Prairie State Generating Co., PSD Appeal 05-05, 13 E.A.D. __ (Aug. 24, 2006). Excerpt attached at Exhibit 3.
[68] Id. at 35-36 (see Exhibit 3).
[69] Id.
[70] EPA, New Source Review Workshop Manual, at B-10.
[71] See pages 15-16, above.

Finally, Proponents cite to and attach a letter from EPA, dated December 13, 2005 (the "Page Letter").[72] IPSC correctly concedes, as it must, that this letter no longer has any legal or even persuasive value as a statement of EPA's position on IGCC.[73] This is because, on October 16, 2006, EPA gave notice of a settlement in which EPA expressly agreed that "the December 13, 2005 document is not final agency action and creates no rights, duties, obligations, nor any other legally binding effects on EPA, the states, tribes, any regulated entity or any person."[74] Instead, EPA's EAB decision in Prairie State, endorsing the consideration of IGCC in a BACT analysis, is the most current, and only legally significant EPA statement on IGCC.

Finally, because EPA's most recent pronouncement, through its EAB, approves of the consideration of IGCC in BACT analyses, and there is nothing in federal regulations (or even in federal guidance in the New Source Review Workshop Manual) that expressly precludes the consideration of IGCC, there can be no argument that the Board's requiring consideration of IGCC under the Utah BACT regulation would be a more stringent "rule" than exists in federal regulations.[75]

6. The Board May Properly Determine the IGCC Must be Included in BACT Analyses by Adjudicating these Requests for Agency Action, Because a Decision that DAQ Must Consider IGCC Does Not Have to be Subject to Rulemaking.

Under the Utah Air Conservation Act, the Board has the power to "hold hearings relating to any aspect of or matter in the administration of this chapter" and "issue orders

[72] See, e.g., IPSC MJP Brief at 14.
[73] See id.
[74] Exhibit 4 (Settlement Agreement); see Proposed Settlement Agreement, Clean Air Act Citizen Suit, 71 Fed. Reg. 61,771, 61,771.
[75] Utah Code Ann. § 19-2-106(2).

necessary to enforce the provisions of this chapter."[76] As PacifiCorp concedes, this power includes the power to establish rules of law by adjudication.[77] In deciding what is, or is not, BACT, the language of the BACT regulation requires that the Board decide this question for each of these facilities through adjudication. The Utah air quality regulations provide that the Board must determine what BACT is "on a case-by-case basis."[78]

Proponents' suggestion that every undefined term in every air quality regulation must be subject to rulemaking before it can be applied would turn the administrative appeal process on its head – indeed, it would make the entire section of the air quality regulations regarding "administrative procedures" irrelevant. The federal government, responsible for supervising nationwide Clean Air Act standards, has not found it necessary to address whether IGCC is BACT through a rulemaking. Instead, as illustrated by the Prairie State case and other adjudications cited above,[79] the EPA and the states have addressed whether IGCC is BACT through the adjudication of individual permit applications. Notably, Proponents cite (without providing context) a law review article and a treatise, rather than any Utah or federal statute, regulation, or case law, in support of their proposition. In short, Proponents offer no persuasive legal basis why this Board should not do the same as others regulatory agencies in the country and determine,

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[76] Utah Code Ann. § 19-2-104(3)(a)-(b) (emphasis added).
[77] PacifiCorp MJP Brief at 10 (citing Salt Lake Citizen's Congress v. Mountain States Tel. & Tel. Co, 846 P.2d 1245, 1252 (Utah 1992) (holding that "an agency must have the power to establish rules of law on a case-by-case basis within the context of its statutory authority" and that "[r]ules of law developed in the context of agency adjudication are as binding as those promulgated by agency rule making.").
[78] Utah Admin. Code R307-101-2.
[79] See pages 22-23, 25, above.

on the basis of full evidentiary hearings in these adjudications, whether and how IGCC must be considered in a BACT analysis.

7. On a Motion for Judgment on the Pleadings, the Executive Secretary's Statement of Facts is Irrelevant.

As described above, the Board must take Sierra Club's factual allegations as true in deciding these motions. Nevertheless, the Executive Secretary submitted statements of facts in his briefs. These statements are irrelevant, because the Board must accept Sierra Club's factual allegations as true.

Sierra Club notes that the Executive Secretary has not cited to any supporting documents for the statements of fact in its two briefs.[80] This alone is a basis for the Board to reject those statements. Rule 7(c)(3)(A) requires that "each fact shall be separately stated and numbered and supported by citation to relevant materials."[81] Failure to comply with this Rule is sufficient for the Board to reject the Executive Secretary's statements.[82] However, where those statements conflict with the facts alleged in Sierra Club's pleadings, those statements become, by definition, "disputed" issues of fact, which cannot be decide on a motion for judgment on the pleadings. And, because disputed issues of fact exist, the Board must deny those motions.

In addition, Sierra Club disputes the following statements in the Executive Secretary's statements of fact:

5. (same in both of the Executive Secretary's briefs):[83] "Integrated Gasification Combined Cycle (IGCC) is a method of producing electricity for gasifying coal,

[80] DAQ MJP Brief in SPC at 3-4, DAQ MJP Brief in IPSC at 3-4.
[81] Utah R. Civ. P. 7(c)(3)(A) (emphasis added).
[82] Bluffdale City v. Smith, 2007 UT App. 25, ¶¶ 6-12, 570 Utah Adv. Rep. 64.
[83] DAQ MJP Brief in SPC at 4, DAQ MJP Brief in IPSC at 3.

removing pollutants before combustion, and then burning the syngas in a modified combined cycle gas-fired power plant. IGCC is not a control technology but rather a separate process from the proposed CFB technology."

The Sierra Club disputes the second sentence of this statement because it is both unsupported by any citation and because it is factually untrue, for purposes of deciding these motions. As stated above, the Board must accept as true the allegation that IGCC is a control technology as described in Utah's definition of "best available control technology."[84] IGCC is also a "production process" and an "available method" for generating electricity from coal within the definition of BACT, as well as an "innovative fuel combustion technology."[85] The Executive Secretary's statement to the contrary has no support and no legal significance at this point in the proceedings.

Accordingly, the factual statements and arguments Proponents make in their briefs describing what IGCC "is" are irrelevant to their motion for judgment on the pleadings.[86] In deciding these motions these motions, the Board must accept as true Sierra Club's allegations in its RFAs and the incorporated comments that "IGCC is a control technology"[87] – and also that IGCC is a "production process," an "available method" for reducing pollution, and an "innovative fuel combustion technology" within the definition of "best available control technology."

Ultimately, after the parties have had a full opportunity to discover, prepare, and present evidence at a hearing, the Board will have to determine a variety of disputed

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[84] Golding, 793 P.2d at 898 ("in considering the factual allegations in the complaint, we take them as true and consider them and all reasonable inferences drawn therefrom in a light most favorable to the plaintiff."); see page 15, above.
[85] See pages 15-16, above.
[86] See, e.g., IPSC MJP Brief at 13 (describing IPSC as "unproven").
[87] See pages 15-16, above.

issues: whether IGCC is a "control technology" within the meaning of Utah's "best available control technology" regulation, whether it is a "production process," "available method," and an "innovative fuel combustion technology." Sierra Club will present expert testimony and evidence that IGCC fits each of these definitions and therefore that it comes within Utah's definition of "best available control technology." At best, Proponents have flagged issues that cannot be resolved without the Board's consideration of all the relevant facts – they have not carried their burden to show that there are no undisputed facts based on the pleadings. At this stage of these proceedings, when the Board must accept Sierra Club's factual allegations as true, the Board must deny Proponents' motions because IGCC comes within the definition of BACT, and Sierra Club has adequately stated a claim on which relief can be granted.

B. The Board Must Deny the Motions for Judgment on the Pleadings on Sierra Club's Claims Regarding Carbon Dioxide and Other Greenhouse Gas Emissions (IPSC RFA # 3, SPC RFA # 1) Because, Taking as True Sierra Club's Factual Allegations, the Sierra Club Has Stated a Claim on Which Relief can be Granted.

As with its claims regarding IGCC, Sierra Club has adequately pled its claims that DAQ was required to consider carbon dioxide, nitrous oxide, and other greenhouse gas emissions in drafting the permits for IPSC Unit 3 and the proposed SPC power plant. On these preliminary motions for judgment on the pleadings, as described above,[88] the Board must take Sierra Club's allegations as true, and draw all inferences in favor of Sierra Club. Under this standard, Sierra Club has adequately pled its claims regarding DAQ's obligations to address greenhouse gases, and the Board should deny Proponents' motions.

[88] At pages 5-9.

1. The Executive Secretary and the Other Proponents' Motions for Judgment on the Pleadings on Sierra Club's Claims Regarding Carbon Dioxide, Nitrous Oxide and Other Greenhouse Gases Are Based on Misperceptions of Those Claims.

Without providing the Board with a copy of Sierra Club's pleadings, the Executive Secretary argues that "Sierra Club makes the single factual allegation that the Executive Secretary did not require regulation of greenhouse gases."[89] The Executive Secretary is wrong. As illustrated by the actual Requests for Agency Action in Exhibit 1 and excerpts from the incorporated comments in Exhibit 2, AR IPSC 2371-72, 2542-50, AR SPC 2307-08, what Sierra Club has alleged is that carbon dioxide, nitrous oxide, and other greenhouse gases are "air pollutants" that the relevant law requires DAQ to consider in several ways in developing an air quality permit.

As Sierra Club alleged in its Requests for Agency Action, DAQ is obligated to consider carbon dioxide, nitrous oxide, and other greenhouse gas emissions both as a regulated pollutant and as part of the collateral environmental impact in the BACT analysis, during which the agency "is required to consider environmental impacts, such as greenhouse gas emissions, when determining BACT for a facility."[90] Sierra Club alleged that DAQ did not adequately consider how carbon dioxide affects the environment, and failed to consider – as part of its BACT analyses – whether alternative processes (including IGCC) could more effectively control the harmful effects of carbon dioxide and other greenhouse gases.[91]

As described above, in deciding these motions for judgment on the pleadings, the Board must take the following facts alleged in Sierra Club's pleadings (and the

[89] DAQ MJP Brief in SPC at 7, DAQ MJP Brief in IPSC at 6.
[90] Exhibit 1, IPSC 4497, SPC RFA p. 4.
[91] Exhibit 1, IPSC 4496-97, SPC RFA pp. 3-4; Exhibit 2, IPSC 2351, SPC 2308.

documents incorporated by reference) as true, and disregard any contrary factual statements made in Proponents' briefing:

1. Carbon dioxide is an air pollutant. Exhibit 2, AR IPSC 1381, 2351, 2370-71, 2546, AR SPC 2307-08.
2. Nitrous oxide is an air pollutant. Exhibit 2, AR SPC 2307-08.
3. Carbon dioxide emissions are extremely harmful, and are generally recognized by Utah and the United States to be a cause of climate change. Exhibit 2, AR IPSC 2547-48, AR SPC 2307-08.
4. The choice of production process can substantially affect emissions of National Ambient Air Quality Standards pollutants, toxics, and carbon dioxide. Exhibit 2, AR IPSC 2546, AR SPC 2308.
5. IGCC is a commercially available production technology for coal-fired power plants that has lower emissions rates and the ability to separate carbon dioxide emissions for sequestration. Exhibit 2, AR IPSC 2546, AR SPC 2308.
6. IGCC would reduce the emissions of carbon dioxide from IPSC Unit 3. Exhibit 2, IPSC 1384, 2351.
7. IGCC would reduce the emissions of carbon dioxide and nitrous oxide from the SPC facility. Exhibit 2, SPC 2308.

2. <u>DAQ Is Required to Regulate Directly Carbon Dioxide as Part of its Administration of the Clean Air Act Program Approved by EPA.</u>

The U.S. Supreme Court is currently considering a suit initiated by twelve states, fourteen conservation groups, and two cities asserting that EPA is required, under the

Clean Air Act, to regulate carbon dioxide and other greenhouse gas pollutants.[92] The Supreme Court will issue its ruling this spring, and the Board should anticipate the possibility of a decision requiring future regulation of greenhouse gas pollutants from coal-fired power plants.

EPA, and states for which EPA has approved a SIP to administer the Clean Air Act, are required to regulate CO_2 and other greenhouse gases as pollutants under the Clean Air Act. Carbon dioxide, nitrous oxide and other pollutants are squarely within the Act's definition of "air pollutant." The Clean Air Act defines "air pollutant" expansively to include "any physical, chemical, biological, radioactive … substance or matter which is emitted or otherwise enters the ambient air."[93] Further, the Clean Air Act specifically includes carbon dioxide in a list of "air pollutants." Section 103(g) directs EPA to conduct a research program concerning "[i]mprovements in nonregulatory strategies and technologies for preventing or reducing multiple air pollutants, including … carbon dioxide, from stationary sources, including fossil fuel power plants."[94] The Clean Air Act requires regulation of air pollutants that "may reasonably be anticipated to endanger human health or welfare."[95] The statutory definition of "welfare" specifically includes effects on climate and weather.[96]

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[92] Massachusetts v. EPA, U.S. Supreme Court Docket No. 05-1120 (cert. granted June 26, 2006). This subsection of the memorandum summarizes legal arguments before that Court and explains why an affirmative ruling from the Supreme Court would affect Utah PSD permits.
[93] 42 U.S.C. § 7602(g) (CAA §302(g)).
[94] 42 U.S.C. § 7403(g)(1) (CAA § 103(g)(1)).
[95] 42 U.S.C. § 7411 (CAA § 111) (establishing "New Source Performance Standards"); 42 U.S.C. § 7521 (CAA § 202) (establishing emission standards from new vehicles).
[96] 42 U.S.C. § 7602 (CAA § 302(h)).

For purposes of these motions for judgment on the pleadings, the Board must take as true Sierra Club's allegation that carbon dioxide is an "air pollutant." Under the plain language of the Clean Air Act, EPA – and the Utah DAQ administering a SIP-approved program – have a legal obligation to regulate CO_2 and other greenhouse gases as pollutants. If the U.S. Supreme Court agrees that greenhouse gases, such as carbon dioxide, must be regulated under the Clean Air Act, such a decision could also require the establishment of carbon dioxide emission limits in this permit for IPP Unit 3 and the proposed SPC plant.

Similarly, Utah state law also supports regulation of greenhouses gases under the minimum federal requirements and state law. The purpose of the Utah Air Conservation Act is to "provide for a coordinated statewide program for air pollution prevention, abatement, and control."[97] The term air pollution "means the presence in the ambient air of one or more air contaminants in such quantities and duration and under conditions and circumstances, as is or tends to be injurious to human health or welfare, animal or plant life, or property, or would unreasonable interfere with the enjoyment of life or use of property as determined by the standards, rules, and regulations adopted by the Air Quality Board (Section 19-2-104)."[98] DAQ has recognized that "the consensus of most scientists worldwide is that increasing concentrations of greenhouse gases will lead to significant climate warming, shifts in precipitation patterns, and rising sea levels, although the magnitude, timing, and regional patterns of these changes cannot be

[97] Utah Code Ann. § 19-2-101(4)(a).
[98] Utah Code Ann. § 19-2-102; Utah Admin. Code R307-101-2.

accurately predicted at this time."[99] Accordingly, because carbon dioxide, nitrous oxide and other greenhouse gases are "air pollutants," existing federal and state legal authority required DAQ to consider greenhouse gas emissions in developing these permits.

3. DAQ Is Required to Consider Carbon in the BACT Collateral Impacts Analysis.

In any case, DAQ's obligation to consider carbon dioxide, nitrous oxide, and other greenhouse gases extends to the BACT analysis. The BACT requirement applies to "each pollutant subject to regulation under [the Act] emitted from, or which results from, such facility."[100] However, even if carbon dioxide is not treated as a regulated pollutant, Sierra Club has adequately alleged in its pleadings that DAQ must still consider carbon dioxide as a non-regulated pollutant in the collateral impacts stage of the BACT analysis.

As Sierra Club has adequately alleged, at the minimum, DAQ must consider emissions of carbon dioxide in its BACT analysis for IPP Unit 3. The federal EAB has interpreted the definition of BACT as requiring consideration of unregulated pollutants in setting emission limits and other terms of a permit, since a BACT determination is to take into account environmental impacts.[101] The Utah BACT regulation expressly requires that the Board determine the best available control technology "on a case-by-case basis taking into account energy, environmental and economic impacts and other costs."[102] In addition, Sierra Club has also incorporated by reference in its pleadings a paper by then-EPA Assistant General Counsel Gregory B. Foote indicating that it is entirely appropriate

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[99] Utah Division of Air Quality, Greenhouse Gas Inventory-1990 and 1993, available at www.airquality.utah.gov/PLANNING/Grnhsgas.htm.
[100] 42 USC § 7475(a)(4) (CAA § 165(a)(4)).
[101] See In Re North County Resource Recovery Associates, 2 E.A.D. 229, 230 (Adm'r 1986), 1986 EPA App. LEXIS 14.
[102] Utah Admin. Code R307-101-2.

for agencies to consider carbon dioxide emissions when evaluating environmental impacts under the new source review permit program.[103]

The essence of the BACT analysis is comparing various pollution control technologies, including their differential collateral environmental impacts to derive emission limitations or other controls. DAQ did not address carbon dioxide or other greenhouse gases to be emitted from the two proposed plants in its BACT analysis. However, such emissions can be quite significant from coal-fired boilers. The selected technologies in the BACT analyses, a circulating fluid bed boiler for SPC and a subcritical (and later a supercritical) boiler for IPSC, will have greater environmental impacts from higher carbon emissions than would the IGCC process. Yet, the IPSC and SPC AOs fail to consider this critically important collateral impact.

Sierra Club has adequately alleged that DAQ had an obligation to consider carbon dioxide, nitrous oxide, and other greenhouse gas emissions in developing the permits for the proposed IPSC and SPC facilities. Taking as true the allegations that carbon dioxide and other greenhouse gases are "air pollutants" and that technology – IGCC – exists that would reduce the emissions from the proposed plants, Sierra Club has stated a claim that DAQ was required to consider these pollutants in the IPSC Unit 3 and SPC permits. As a result, the Board should deny the motions for judgment on the pleadings regarding these claims.

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[103] Exhibit 2, IPSC 2542-49, SPC 1282 (Gregory B. Foote, Considering Alternatives: The Case for Limiting CO2 Emissions from New Power Plants through New Source Review (discussing the regulatory background to support consideration of CO2 impacts when permitting a new source and, in particular, a new coal-fired power plant)).

C. The Board Must Deny the Motions for Judgment on the Pleadings on Sierra Club's Claim Regarding Coal Chemistry Data (IPSC RFA # 5) Because, Taking as True Sierra Club's Factual Allegations, Sierra Club Has Stated a Claim on Which Relief Can Be Granted.

The Board must deny IPSC's motion for judgment on the pleadings regarding Sierra Club's fifth claim in its IPSC Request for Agency Action for the sole reason that, even though IPSC references materials outside the pleadings, IPSC has not carried its burden of showing that there are no issues of material fact remaining regarding that claim. Instead, taking as true the allegations in Sierra Club's pleadings, it is clear that Sierra Club has adequately stated a claim on this issue. The Board must apply the proper standard for reviewing a motion for judgment on the pleadings and deny IPSC's invitation to prematurely decide this issue on the merits.

Sierra Club's fifth claim asserts, in full:

> IPSC's permit application did not contain precise coal chemistry data due to the fact that the corporation had not identified the actual coal to be burned at IPP Unit 3. The failure to include coal chemistry data prevents an accurate determination of percent removal efficiency limits, short term emission rates, and total mass emissions of pollutants such as mercury. Moreover, the description of the coal type and coal quality in the permit application is often vague and conflicting. Thus, reliance on such information by UDAQ is arbitrary and capricious. In the event IPSC plans to blend coal, the final permit should contain a coal quality/coal blending requirement. UDAQ wrongfully deleted such a provision from an earlier draft of the permit.
>
> In summary, the permit application was fatally flawed by failing to include coal quality and/or coal blending information. The application also contained internally inconsistent information on coal quality. UDAQ erroneously issued a final permit without adequate coal quality data. For these reasons, the AO is illegal and should be rescinded and/or remanded to the agency.[104]

Notwithstanding the characterization in IPSC's brief, Sierra Club's claim is that DAQ set emissions limits without adequate coal data, that the inadequacy of the data

[104] Exhibit 1, AR IPSC 4498 (emphasis added).

results from vague and conflicting information in the submissions, and that the result of this inadequate data is a permit that contains improper emission rates and limits.

For purposes of evaluating whether Sierra Club has stated a claim, on the motion for judgment on the pleadings, the Board must take as true the following facts alleged in Sierra Club's pleadings:

1. IPSC did not include precise coal chemistry data with its application. Exhibit 1, AR IPSC 4498.
2. Coal chemistry, its chlorine content specifically, is important because it affects the ability of existing control equipment to remove mercury from exhaust streams. Exhibit 2, AR IPSC 2477.
3. Accurate coal chemistry data is required to ensure an accurate determination of percent removal efficiency limits, short term emission rates, and total mass emissions of pollutants such as mercury. Exhibit 1, AR IPSC 4498.
4. IPSC's application did not contain coal quality information or coal blending information to ensure all emissions limitations will be met. Exhibit 1, AR IPSC 4498; Exhibit 2, AR IPSC 2350.
5. For some emissions, like mercury, IPSC proposes to look at the range of coals that IPP Unit 3 will be designed to burn over the life of the plant (i.e., bituminous and subbituminous). The range of mercury content of the coal (.02 ppm by weight to.15 ppm) provided by IPP is too broad and vague to be relied upon. Exhibit 2, AR IPSC 2350.

6. The September 8, 2003 Technical Memorandum states that IPSC will burn only Western bituminous coals. This is inconsistent with other statements in the administrative record regarding the type of coal to be burned at Unit 3. Exhibit 2, AR IPSC 2350.
7. An earlier draft of the permit contained a 20% blending limit which was wrongfully eliminated from the final permit. Exhibit 2, AR IPSC 2350.
8. It is essential that an air quality permit contain an enforceable coal quality/blending requirement to ensure that short term emission limits are met as well as other permit conditions. Exhibit 2, AR IPSC 2350.

On this motion for judgment on the pleadings, the only question the Board must answer is whether there is a dispute regarding the adequacy of the coal data submitted. Taking Sierra Club's allegations as true, and contrasting them with the statements IPSC makes in its brief, shows clearly that issues of disputed material fact remain regarding the adequacy of IPSC's coal chemistry data.

The air quality regulations require that an applicant submitting a notice of intent to construct supply information regarding "the type and quantity of fuels employed."[105] However, this requirement does not exist in a vacuum: the federal Clean Air Act, the Utah Air Conservation Act, and DAQ regulations that implement these Acts have as their overriding purpose "air pollution prevention, abatement, and control."[106] The requirements for an application for a new source permit[107] – including information concerning type and quantity of fuel, composition and characteristics of effluent streams,

[105] Utah Admin. Code R307-401-5(2)(a).
[106] Utah Code Ann. § 19-2-101(4)(a).
[107] Utah Admin. Code R307-401-5.

types and concentration of air contaminants, analysis of best available control technology, and "[a]ny other information necessary to determine if the proposed source or modification will be in compliance with Title R307" – exist to ensure that a new permit complies with the pollution prevention, abatement, and control purpose that guides DAQ's mission. Providing incomplete, vague, contradictory, or otherwise inadequate data on the composition and chemistry of the coal an applicant intends to use, as Sierra Club alleges IPSC has done in this case, makes any DAQ decision on permit conditions regarding coal composition arbitrary and capricious.[108]

Sierra Club disputes that IPSC has presented a "worst-case" coal-supply scenario,[109] and alleges that the applicant presented coal chemistry data inadequate to ensure that all emissions limitations will be met. Sierra Club further alleges that IPSC has submitted vague and conflicting coal chemistry data that does not reflect a worst-case scenario. This includes, for example, IPSC's reference to a range of mercury contents for its coal, instead of a single figure at the higher end of that range that would truly represent the worst case. Likewise, IPSC has claimed that it would only burn Western bituminous coal, yet Condition 19 of the final AO allows for burning up to 30% subbituminous coal, which produces higher pollution emissions than bituminous coal. Most significantly, DAQ's draft permit in this matter required a 20% percent blending limit to ensure that emissions limitations would be met.[110] The final permit increased this

[108] An agency action is void under the Utah Administrative Procedures Act if it "is based upon a determination of fact, made or implied by the agency, that is not supported by substantial evidence when viewed in light of the whole record." Utah Code Ann. § 63-43b-16(4)(g).
[109] IPSC MJP Brief at 18-19.
[110] Exhibit 2, AR IPSC 2350.

percentage blending limit, and DAQ has not adequately explained the reason it changed this essential requirement for ensuring that pollution emission limitations will be met.[111]

In short, IPSC is asking the Board to rule on the merits of whether its coal chemistry data was inadequate. On a motion for judgment on the pleadings, the Board must accept Sierra Club's allegations as true, and draw all relevant inferences in favor of Sierra Club. Whether or not the IPSC submitted adequate coal chemistry data, whether DAQ's decision to draft the permit based on the inadequate data submitted was arbitrary and capricious, and whether DAQ adequately explained its reversal of direction regarding the percentage blending limit that DAQ removed from the final permit are questions involving underlying disputes of material fact that cannot be resolved on a motion for judgment on the pleadings. The Board accordingly must deny IPSC's motion.

D. The Board Must Exclude Materials Outside of the Pleadings, or, if the Board Chooses to Convert These Motions to Motions For Summary Judgment, the Board Should Continue Decision on These Motions Until Sierra Club has Reasonable Time to Conduct Discovery

It is clear under Utah law that a party which moves for judgment on the pleadings is limited to arguments based on the facts and claims alleged in the pleadings.[112] All of the Proponents except IPSC adhere to this basic principle. Yet all the parties, including IPSC, have chosen to present their motions as for a judgment on the pleadings. Because of Proponents' choices, the Board must apply the standards for such motions and, as

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[111] When an agency alters direction without providing adequate explanation, the agency's decision is void under the Utah Administrative Procedures Act because it is "contrary to the agency's prior practice, unless the agency justifies the inconsistency by giving facts and reasons that demonstrate a fair and rational basis for the inconsistency." Utah Code Ann. § 63-43b-16(4)(h)(iii).

[112] Colman, 795 P.2d at 624 (the tribunal may "look solely to the material allegations of [the plaintiff's] complaint").

discussed above, the Board must exclude IPSC's exhibits from consideration on these particular motions.[113]

Utah Rule of Civil Procedure 12(c), which governs motions for judgments on the pleadings, does provide that the Board has discretion to consider materials outside the pleadings.[114] However, it may only do so if it coverts the motion to one for summary judgment.[115] In the event the Board decides to do so, "all parties shall be given reasonable opportunity to present all material made pertinent to such a motion by Rule 56."[116] There is no reason to convert Proponents' pending motions to motions for summary judgment: denying Proponents' motions at this preliminary stage based on the pleadings alone does not prevent Proponents from moving for summary judgment after all sides have had an opportunity to take discovery and prepare and present expert testimony on the issues in this matter.[117] The schedules in both matters expressly provide for the filing of post-discovery dispositive motions by August 3, 2007 (in the SPC matter) and September 5, 2007 (in the IPSC matter).

In any event, and for the same reasons described above, a motion for summary judgment on any of these issues must fail. The standard for summary judgment requires a tribunal to ""examine all of the facts presented and the inferences to be drawn

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[113] Id.
[114] Utah Rule of Civil Procedure 12(c) provides: "[i]f, on a motion for judgment on the pleadings, matters outside the pleadings are presented to and not excluded by the court, the motion shall be treated as one for summary judgment and disposed of as provided in Rule 56, and all parties shall be given reasonable opportunity to present all material made pertinent to such a motion by Rule 56."
[115] Utah R. Civ. P. 12(c).
[116] Id.
[117] The fact that none of the Proponents has included a properly supported statement of undisputed facts, as required by Utah R. Civ. P. 7(c)(3)(A) is a further reason the Board should not convert these motions into motions for summary judgment.

therefrom in the light most favorable to the nonmoving party,"[118] and only grant judgment if "'there is no genuine issue as to any material fact' and 'the moving party is entitled to a judgment as a matter of law.'"[119] Sierra Club has sufficiently shown that these claims involve material issues of fact, and that the Board cannot grant Proponents' motions, whether on the pleadings or on summary judgment.

Furthermore, the Board cannot convert these motions to motions for summary judgment without providing a reasonable opportunity for Sierra Club to obtain discovery and to present evidence and affidavit contesting the factual allegations suggested in Proponents' briefs. The conversion process under Rule 12(c) "includes giving the parties reasonable notice and opportunity to submit all pertinent summary judgment materials for the [Board]"s consideration."[120] As the Utah Supreme Court has noted, "if a motion to dismiss is converted to a motion for summary judgment, it must only be done so as to not create procedural prejudice to one of the parties," because the rule "gives the opposing party an opportunity to gather evidence to rebut the movant's evidence. Without such a rule, one party could have the benefit of significant, supporting evidence while the other party would be left to rely solely on the unsubstantiated pleadings."[121] It would also be

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[118] Grynberg v. Questar Pipeline Company, 2003 UT 8, ¶ 20, 70 P.3d 1 (quoting Utah R. Civ. P. 56(c)) (emphasis added).
[119] Fennell v. Green, 2003 UT App 291, ¶ 6, 77 P.3d 339.
[120] Tuttle v. Olds, 2007 UT App 10, ¶ 8, 569 Utah Adv. Rep. 10 (noting that "[t]he notice and opportunity to submit requirements are especially important with respect to the party against whom judgment is entered."); see also Strand v. Associated Students of Univ. of Utah, 561 P.2d 191, 193 (Utah 1977) (stating that the opportunity for the non-moving party to submit rule 56 material is particularly important).
[121] Colman, 795 P.2d at 625.

improper to allow the moving party, in this case Proponents, to present evidence in their reply briefs, without affording Sierra Club the opportunity to respond.[122]

Although there is no reason for the Board to convert these motions for judgment on the pleadings into motions for summary judgment, Sierra Club requests that, if the Board decides to treat these motions as motions for summary judgment, that it continue the motions until the August and September deadlines for post-discovery dispositive motions provided in the schedules for these matters. Together with this Consolidated Opposition, Sierra Club has made a formal motion to this effect as provided in Utah Rule of Civil Procedure 56(f).[123] An affidavit in conformance with Rule 56(f) is attached to that motion.[124] The Utah Supreme Court has "held on numerous occasions that rule 56(f) motions opposing a summary judgment motion on the ground that discovery has not been completed should be granted liberally unless they are deemed dilatory or lacking in merit."[125] Because the discovery process has barely started in these matters, and Proponents will have scheduled opportunities to renew their motions as properly-supported motions for summary judgment after discovery is completed, the Board should deny Proponents' motions for judgment on the pleadings without converting them to motions for summary judgment.

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[122] Badger v. Brooklyn Canal Co., 922 P.2d 745, 753 (Utah 1996).
[123] Utah R. Civ. P. 56(f) provides that "[s]hould it appear from the affidavits of a party opposing the motion that he cannot for reasons stated present by affidavit facts essential to justify his opposition; the court may refuse the application for judgment, or may order a continuance to permit affidavits to be obtained or depositions to be taken or discovery to be had or may make such other order as is just."
[124] Strand, 561 P.2d at 193-94.
[125] Salt Lake County v. Western Dairymen Coop., Inc., 2002 UT 39,¶ 24, 48 P.3d 910.

Dated: March 19, 2007

_____/s/_____
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CERTIFICATE OF SERVICE

I hereby certify that on this 19th day of March 2007, I caused a copy of the foregoing Consolidated Opposition to Motions for Judgment on the Pleadings to be emailed to the following:

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UTAH DEPARTMENT OF
ENVIRONMENTAL QUALITY
NOV 16 2006
DIVISION OF AIR QUALITY

BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station, Millard County, Utah Project Code: N0327-010 DAQE-AN0327010-04	:	REQUEST FOR AGENCY ACTION

FIRST AMENDED REQUEST FOR AGENCY ACTION
OR, IN THE ALTERNATIVE, SECOND REQUEST FOR AGENCY ACTION[1]

Pursuant to Utah Administrative Code R307-103-3(1) and Utah Code § 63-46b-3(3), the Utah Chapter of the Sierra Club and Grand Canyon Trust hereby file their Request for Agency Action with Richard W. Sprott, Executive Secretary of the Utah Air Quality Board. The Sierra Club and Grand Canyon Trust seek review of the October 15, 2004 decision by the Utah Division of Air Quality and the Executive Secretary (collectively "UDAQ") to issue an Approval Order (AO) granting a Prevention of Significant Deterioration (PSD) permit to Intermountain Power Service Corporation (IPSC) to construct and operate an additional 950 megawatt (MW) coal-fired power plant Unit #3 at the Intermountain Power Plant in Millard County, Utah (DAQE-AN0327010-04)(Project Code: N0327-010). Pursuant to Utah Admin. Code R307-103-3(2), R307-103-6(2)(c), and R307-103-3, the Sierra Club and Grand Canyon Trust submit with

[1] Sierra Club and Grand Canyon Trust request that they be allowed to amend their November 15, 2004 Request for Agency Action with the additions indicated herein. In the alternative, the conservation groups file this pleading as a Second Request for Agency Action as an independent Second Request for Agency Action **without** withdrawing their November 15, 2005 Request for Agency Action. A Statement of Standing/Petition to Intervene in Support of Second Request for Agency Action is attached.

proposed IPSC Unit 3 from a subcritical to supercritical pulverized coal fired boiler. On August 17, 2006, DAQ responded that if found "in accordance with Condition 7 of the Approval Order number DAQE-AN0327010-04, a supercritical PC boiler is equivalent to the permitted unit," Letter from Rick Sprott to Doug Hunter, August 17, 2006, thereby approving the project changes. Sierra Club learned of the IPSC request on October 13, 2006 and of DAQ's decision to approve the IPSC request on October 17, 2006 when it received an emailed copy of the August 17, 2006 DAQ approval letter.

DAQ issued its August 17, 2006 letter without first providing public notice and comment on the significant project changes proposed by IPSC to the Unit 3 facility. On November 13, 2006, Sierra Club mailed and emailed a formal request to Rick Sprott, Executive Director of DAQ responding to the project changes for the IPSC Unit 3 facility and requesting that DAQ notify the public of those changes and designate a comment period for the public to respond to those changes. On November 15, 2006 Rick Sprott denied that request.

B. Statement of Reasons

As set forth below and in the Sierra Club and Grand Canyon Trust's comments, UDAQ's approval of IPSC's PSD permit fails to comply with the Clean Air Act, the Utah Air Conservation Act, and the Utah Administrative Code. The Sierra Club and Grand Canyon Trust hereby incorporate and reference their comments dated April 14, 2003, May 20, 2004, June 30, 2004, and July 16, 2004, and the documents submitted in support of those comments.

In addition, the Sierra Club and Grand Canyon Trust sets forth the basis for its request for agency action below:

1. UDAQ Failed to Consider Adequately Integrated Gasification Combined Cycle (IGCC) in its BACT Determination and Failed to Require the Production Process for IPP Unit 3.

Integrated Gasification Combined Cycle (IGCC) is a method of producing electricity by gasifying coal, removing pollutants – including greenhouse gases – before combustion, and then burning the "clean" syngas in a modified combined cycle gas-fired power plant. IGCC is an available, demonstrated, clean coal combustion technology with significant emission reduction benefits.[3] As such, UDAQ is required to evaluate this technology comprehensively as part of its BACT analysis. The agency, however, claims otherwise.

[3] The Sierra Club and Grand Canyon Trust have, in their May 20, 2004 comments on the ITA for the IPP project, detailed the basis for this and other statements regarding the need to evaluate IGCC as part of a proper BACT analysis for IPP. Because the organizations have already referenced and incorporated those comments into their Request for Agency Action, they will not repeat those detailed arguments here.

To argue that it is not required to evaluate IGCC as part of BACT, UDAQ contends that "the scope of the BACT analysis is limited to control technologies that can be applied to the emission unit proposed by the applicant." Response to Comments at 7, #12. However, UDAQ's interpretation of the BACT analysis requirement is erroneous. Consideration of inherently lower emitting power production processes and techniques such as IGCC is required by Utah Admin. Code R307-101-2, the state regulation defining BACT. Legislative history, EPA guidance, the actions of regulators in other states, and other relevant considerations additionally confirm that because consideration of the process design is a necessary part of the BACT analysis, thorough evaluation of IGCC is mandated.

UDAQ also contends that while it was not required to consider IGCC in its BACT analysis, the evaluation was done. Response to Comments at 7, #12. This analysis – a top-down review comparing the proposed pulverized coal-fired power plant to both circulating fluidized bed and IGCC plants of similar size – is legally and technically inadequate. *See* Appendix I-8 of the NOI. It contains fundamental flaws in both methodology and assumptions, as well as significant mathematical errors. These flaws result in a greatly overstated determination of the cost of IGCC and the amount of pollutants emitted by IGCC. These errors are compounded by an improper method of calculating incremental costs that, when taken together with the other errors, exaggerate the incremental costs of pollution removed by the IGCC plant by two orders of magnitude.

To the extent that UDAQ suggests that it has now revised its review of IGCC for the purposes of BACT, Response to Comments at 8, #14, this revision is inadequate for the purposes of state and federal law. For example, this review was not subject to public notice and comment. Moreover, because the Sierra Club and Grand Canyon Trust have not had the opportunity to assess the revised analysis, they reserve the right to challenge its content. Because UDAQ states that this revised analysis determined IGCC is not appropriate for IPP Unit 3, the conclusions of the evaluation are incorrect.

Finally, as the Sierra Club and Grand Canyon Trust make clear in their May 20, 2004 Comments, the analysis required by law shows that IGCC **is** BACT for IPP Unit 3. This is because IGCC is an available technology, is technically feasible for the IPP project, and is the top ranked control technology. In addition, proper consideration of economic, environmental and energy impacts confirms that IGCC is BACT for IPP Unit 3.

In sum, UDAQ is required to consider IGCC exhaustively as part of its BACT analysis. The existing analysis, presented at Appendix I-8 of the NOI, is fatally flawed. The revised analysis errs in that it concludes IGCC is not appropriate for the IPP Unit 3. As a result, UDAQ has failed its statutory and regulatory duties to examine IGCC adequately and to require the Intermountain Power Service Company to utilize IGCC for its power plant expansion pursuant to a BACT determination. Until UDAQ takes these steps, the AO is illegal and should be rescinded and/or remanded to the agency for proper BACT analysis.

2. UDAQ Failed to Consider Adequately a Supercritical PC Boiler in its BACT Determination and Failed to Require Installation of this Technology for IPP Unit 3.

For essentially the same reasons provided above, UDAQ's consideration of supercritical PC boiler technology is legally inadequate and therefore the AO is fatally flawed. Supercritical boilers are up to 7% or more efficient than subcritical boilers. As a result, they use less fuel and emit less carbon dioxide. Further, such supercritical boilers achieve up to 17% lower emission rates of carbon monoxide (CO), nitrogen oxides (NOx) and sulfur oxides (SOx), as well as up to 15% lower PM emission rates.

Yet, UDAQ argues that it need not analyze this technology as part of its BACT determination. Response to Comments at 8, # 15. The agency's conclusion is flawed. Consideration of inherently lower emitting power production processes and techniques such as supercritical boiler is required by Utah Admin. Code R307-101-2, the state regulation defining BACT. Legislative history, EPA guidance, the actions of regulators in other states, and other relevant considerations additionally confirm that because consideration of the process design is a necessary part of the BACT analysis, thorough evaluation of this technology is mandated.

To the extent that UDAQ suggests that it has now revised its review of supercritical boiler technology for the purposes of BACT analysis, Response to Comments at 8, #15, this revision is inadequate for the purposes of state and federal law. For example, this review was not subject to public notice and comment. Moreover, because the Sierra Club and Grand Canyon Trust have not had the opportunity to assess the revised analysis, they reserve the right to challenge its content. Because UDAQ states that this revised analysis determined that a supercritical boiler is not appropriate for IPP Unit 3, the conclusions of the evaluation are incorrect.

Rather, evaluation of supercritical boilers is required, as this technology, although inferior to IGCC, is an available technology, is technically feasible for the IPP project, and is a better ranked control technology than that currently proposed for Unit 3. In sum, UDAQ is required to consider supercritical boiler technology exhaustively as part of its BACT analysis. The revised analysis errs in that it has not been subject to public comment and it concludes this technology is not appropriate for the IPP Unit 3. As a result, UDAQ has failed its statutory and regulatory duties to examine supercritical boiler technology adequately and to require the IPSC to utilize a supercritical boiler pursuant to a BACT determination. Until UDAQ takes these steps, the AO is illegal and should be rescinded and/or remanded to the agency for proper BACT analysis.

3. UDAQ Erroneously Failed to Address Carbon Dioxide and Other Greenhouse Gas Emissions.

In approving the construction and operation of IPP Unit 3, UDAQ did not address or set limits on carbon dioxide (CO_2) or other greenhouse gas emissions from the new unit. Typically, coal-fired boilers emit significant greenhouse gases. Yet, UDAQ declined to address greenhouse

emissions, based on its belief that it has no legal or regulatory duty to limit or control these emissions. Response to Comments at 9, #16. UDAQ's understanding of Utah law is misguided.

Pursuant to the Clean Air Act and Utah Air Quality Act and their implementing rules, the State of Utah is obligated to regulate greenhouse gases. Further, pursuant to the definition of BACT, Utah Admin. Code R307-101-2, the agency is required to consider environmental impacts, such as greenhouse gas emissions, when determining BACT for a facility. Because UDAQ did not address, set limits on, or factor greenhouse emissions into its BACT analysis, the agency has failed its statutory and regulatory duties. Until UDAQ takes these steps, the AO is illegal and should be rescinded and/or remanded to the agency for proper consideration and regulation of these gases.

4. UDAQ Did Not Properly Set Sulfur Dioxide (SO_2) Emission Limits.

In authorizing IPP Unit 3, UDAQ did not properly set emission limits for sulfur dioxide. The final Unit 3 AO imposes SO_2 limits of 0.10 lb/MMBtu (24-hr block average) and 0.09 lb/MMBtu (30 day rolling average). The administrative record does not support these limits, and UDAQ's adoption of these limits lacks support in the administrative record.

For example, these emission limits and corresponding control efficiencies are not reflective of the maximum degree of emissions reduction that can be achieved by the proposed SO2 control equipment, as required by the Utah definition of BACT. Utah Admin. Code R307-101-2 & R307-401-6(1). As Intermountain Power Service Company states in their NOI, such controls can achieve 98% SO_2 reduction. At best, the 0.10 lb/MMBtu SO_2 limit would equate to a 92% reduction in SO_2 emissions. Thus, the emission levels are too low.

UDAQ further suggests that it is purposefully setting relaxed SO_2 emission limits so that the source can meet them on a continuous basis. Again, this reasoning is not supported by law or fact. First, the record confirms that Unit 3 will be able to meet appropriately more stringent standards routinely – the control equipment is designed to do just that. Second, UDAQ admits that the SO_2 control efficiency necessary to meet the Unit 3 emission standards is **lower** than the efficiency of existing well-controlled sources, such as IPP Units 1 and 2. Indeed, the two existing IPP units are meeting 94.5% removal efficiency with a lower sulfur-content coal than the worst case "design coal" for Unit 3. Third, UDAQ bases a Unit 3 emission limit on worst case sulfur content. This means that the source, which will likely be burning cleaner coal the majority of the time, will be able to meet stricter emission limits.

UDAQ must include SO_2 removal efficiency requirements in the AO. This is because the SO_2 BACT emission limits are based on worst case uncontrolled SO_2 emissions. An efficiency requirement would ensure proper operation and maintenance of the scrubber regardless of the sulfur content in the coal and even when lower sulfur content coal is burned. Control efficiency requirements are further warranted because operation of IPP Unit 3 will adversely impact visibility at nearby Class I areas, including Capitol Reef National Park, where SO_2 increment violations are occurring. As a result of these concerns, the removal efficiency requirement

should reflect, at the very least, what the wet scrubber can achieve – at a minimum 94.5% SO_2 removal efficiency.

Thus, UDAQ's relaxed SO_2 BACT emission requirements are not grounded in law or fact and are too lenient. Similarly, the agency's decision not require both emission limits **and** removal efficiency requirements is erroneous. As a result, the AO is illegal and should be rescinded and/or remanded to the agency for proper consideration and regulation of SO_2.

5. UDAQ Failed to Require Coal Chemistry Data.

IPSC's permit application did not contain precise coal chemistry data due to the fact that the corporation had not identified the actual coal to be burned at IPP Unit 3. The failure to include coal chemistry data prevents an accurate determination of percent removal efficiency limits, short term emission rates, and total mass emissions of pollutants such as mercury. Moreover, the description of the coal type and coal quality in the permit application is often vague and conflicting. Thus, reliance on such information by UDAQ is arbitrary and capricious. In the event IPSC plans to blend coal, the final permit should contain a coal quality/coal blending requirement. UDAQ wrongfully deleted such a provision from an earlier draft of the permit.

In summary, the permit application was fatally flawed by failing to include coal quality and/or coal blending information. The application also contained internally inconsistent information on coal quality. UDAQ erroneously issued a final permit without adequate coal quality data. For these reasons, the AO is illegal and should be rescinded and/or remanded to the agency.

6. UDAQ Failed to Require Use of Continuous Opacity Monitoring Data to Ensure Compliance with the Visible Emissions BACT Limit.

In the AO, UDAQ required that visible emissions from all baghouses (including the Unit 3 main boiler stack) shall not exceed 10 percent opacity. AO, Condition 12. UDAQ specified that opacity observations shall be conducted according to 40 C.F.R. Part 60, Appendix A, Method 9, which is a manual method of measuring opacity requiring a certified opacity inspector to be present. No frequency for Method 9 observations is specified. Such unspecified monitoring is not sufficient to ensure continuous compliance with the opacity limit. This source will be equipped with a continuous opacity monitoring system (COMS), Condition 23 of the AO, and thus UDAQ must require the use this COMS to ensure continuous compliance with the visible emissions BACT limit as stated in 40 C.F.R. §§ 60.47a through 60.49a. Because UDAQ did not, the AO is illegal, and should be rescinded and/or remanded to the agency to ensure continuous compliance with the visible emission limit.

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BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – the Sevier Power Company 270 MW Coal-Fired Power Plant, Sevier County Project Code: N2529-001 DAQE-AN2529001-04	:	REQUEST FOR AGENCY ACTION

REQUEST FOR AGENCY ACTION

Pursuant to Utah Administrative Code R307-103-3(1) and Utah Code § 63-46b-3(3), the Utah Chapter of the Sierra Club and Grand Canyon Trust hereby file their Request for Agency Action with Richard W. Sprott, Executive Secretary of the Utah Air Quality Board. The Sierra Club and Grand Canyon Trust seek review of the October 12, 2004 decision by the Utah Division of Air Quality and the Executive Secretary (collectively "UDAQ") to issue an Approval Order (AO) allowing the Sevier Power Company[1] to construct and operate a 270 MW coal-fired power plant in Sigurd, Sevier County, Utah (DAQE-AN2529001-04)(Project Code: N2529-001). Pursuant to Utah Admin. Code R307-103-3(2), R307-103-6(2)(c), and R307-103-3, the Sierra Club and Grand Canyon Trust submit with this Request for Agency Action a Statement of Standing/Petition to Intervene and the supporting affidavits of Cindy Roberts, Howard Cherry, and Brian Cass.

I. Permit Number and Date of Mailing

As mentioned above, Sierra Club and Grand Canyon Trust are contesting the Approval Order signed by Richard W. Sprott, Executive Secretary of the Utah Air Quality Board, on October 12, 2004 to authorize the construction and operation of the Sevier Power Company 270 MW Coal-Fired Power Plant in Sigurd, Utah (DAQE-AN2529001-04)(Project Code: N2529-001). According to UDAQ, the date of mailing of the AO is October 12, 2004.

[1] According to UDAQ, NEVCO Energy Company, LLC, is the parent company of the Sevier Power Company.

Sierra Club and Grand Canyon Trust have been involved throughout the permitting process for the proposed Sevier Power Company power plant. On October 17, 2003, Sierra Club and Grand Canyon Trust submitted extensive comments on the proposed project in advance of the public comment period, detailing the permitting requirements pertaining to the permit application. The Sierra Club and Grand Canyon Trust participated in a UDAQ public hearing held in Richfield, Utah on March 18, 2004. In addition, on April 9, 2004 and within the designated public comment period, Sierra Club and Grand Canyon Trust submitted extensive comments on the UDAQ Intent to Approve the Sevier Power Company permit. Following the re-opening of the comment period, Sierra Club and Grand Canyon Trust supplemented its April 9, 2004 comments with additional comments dated June 30, 2004 and July 16, 2004.

On October 12, 2004, Richard W. Sprott, Executive Secretary of the Utah Air Quality Board, signed an AO authorizing construction and operation of the proposed Sevier Power Company 270 MW circulating fluidized bed (CFB) coal-fired power plant. According to the Approval Order, the operation of the power plant would allow air emissions increases, in tons per year, of: 177.4 of PM-10; 1066.6 of NO_x; 233.9 of SO_2; 1278.6 of CO, and 53.4 of VOCs, and 24.7 of HAPs. With the AO, UDAQ released a memorandum titled "Response to Comments received on Sevier Power Company," authored by John D. Jenks, Environmental Engineer.

B. Statement of Reasons

As set forth below and in Sierra Club and Grand Canyon Trust's comments, UDAQ's approval of Sevier Power Company PSD permit fails to comply with the Clean Air Act, the Utah Air Conservation Act, and the Utah Administrative Code. Sierra Club and Grand Canyon Trust hereby incorporate and reference their comments dated October 17, 2003, April 9, 2004, June 30, 2004, and July 16, 2004, and the documents submitted in support of those comments.

In addition, the Sierra Club and Grand Canyon Trust sets forth the basis for its request for agency action below:

1. UDAQ Failed to Address Carbon Dioxide and Other Greenhouse Gas Emissions.

The Sevier Power Company estimates that the proposed power plant has the potential to emit 2.2 million tons of carbon dioxide (CO_2) and 1,640 tons of nitrous oxide (N_2O) each year. Both CO_2 and N_2O are greenhouse gases. N_2O has a global warming potential 296 times that of CO_2. N_2O is of significant concern because circulating fluidized bed boilers, such as the one being proposed by the Sevier Power Company, emit significantly more N_2O than conventional pulverized coal boilers.

UDAQ did not address these or other greenhouse emissions during the permitting process based on its belief that "UDAQ has no legal or regulatory authority to limit or control these emissions." Response to Comments at 29 (#83). However, UDAQ notes that "greenhouse gas emissions are potentially an area of concern." Id. Pursuant to the Clean Air Act and Utah Air Quality Act and its implementing rules, the State of Utah has the legal obligation to regulate

greenhouse gases. Further, pursuant to the definition of "best available control technology" (BACT), Utah Admin. Code R307-101-2, Utah is required to consider other environmental impacts, such as greenhouse gas emissions, when determining BACT for a facility. Because UDAQ did not undertake this consideration, the Sevier Power Company permit should be declared illegal, should be rescinded, and/or should be remanded to UDAQ to properly consider and regulate these pollutants in a PSD permit.

2. UDAQ Failed to Consider Adequately Integrated Gasification Combined Cycle in its BACT Determination for Sevier Power Company Facility.

Integrated Gasification Combined Cycle (IGCC) is a method of producing electricity by gasifying the coal, removing pollutants – including greenhouse gases – before combustion, and then burning the "clean" syngas in a modified combined cycle gas-fired power plant. IGCC is an available, demonstrated clean coal combustion technology with significant emission reduction benefits. As such, UDAQ is required to evaluate this technology comprehensively as part of its BACT analysis. To justify its failure to undertake this analysis, UDAQ suggests that "BACT is used as a control technology after selection of the process to be so controlled." Response to Comments at 30 (#84). UDAQ concludes that requiring the consideration of IGCC as part of the BACT analysis is "redefining the source." Id.

UDAQ's legal conclusion regarding the requirements of the BACT analysis is erroneous. Consideration of inherently lower emitting power production processes and techniques such as IGCC is required pursuant to Utah Admin. Code R307-101-2, which defines BACT. As the rule makes clear, consideration of the process design is a necessary part of the BACT analysis. Sevier Power Company did not consider IGCC in its BACT analysis for its proposed power plant, and UDAQ did not evaluate IGCC in its BACT review or determination. Therefore, the Sevier Power Company permit should be declared illegal, should be rescinded, and/or remanded to the agency for proper BACT analysis.

3. UDAQ Failed to Provide Adequate Justification for Not Requiring Sevier Power Company to Meet the Most Stringent NO_x BACT Limits Proposed or Required for Other CFB Boilers.

UDAQ determined that a NO_x emission limit of 0.10 lb/MMBtu, 24-hour rolling average, represents BACT for the proposed CFB boiler. However, NO_x BACT emissions limits for other power plants, including several proposed CFB boilers, are more stringent that the rate proposed for the power plant. Selective Catalytic Reduction (SCR) has been determined to be the Best Available Control Technology for NO_x for most recently permitted coal-fired power plants. Yet, UDAQ failed to provide a reasoned justification for not requiring or evaluating more stringent NO_x emission limits, or installation of SCR, in its BACT determination. Therefore, the Sevier Power Company AO should be declared illegal, should be rescinded, and/or remanded to the agency for proper BACT analysis.

EXHIBIT 2

Wasatch Clean Air Coalition
Utah Chapter Sierra Club
Great Basin Foundation
Rocky Mountain Office of Environmental Defense
Land and Water Fund of the Rockies
Clean Air Task Force

April 14, 2003

RECEIVED
APR 15 2003
AIR QUALITY

Rick Sprott
Director
Utah Division of Air Quality
150 North 1950 West
Salt Lake City, Utah 84116

Re: Comments on Intermountain Power Service Corporation Notice of Intent for Intermountain Power Project (Dec. 2002)

Dear Mr. Sprott:

The Wasatch Clean Air Coalition, Utah Chapter of the Sierra Club, Great Basin Foundation, Rocky Mountain Office of Environmental Defense, Land and Water Fund of the Rockies, and Clean Air Task Force, respectfully submit the following comments regarding the December 2002 Notice of Intent (NOI) for the Intermountain Power Project (IPP). We believe it would be contrary to law for Utah to determine that the application materials are complete or to provide public notice of the state's intent to approve the proposed construction of this facility without first addressing the serious deficiencies examined in detail below. We greatly appreciate your consideration of our views.

FEDERAL AND STATE CLEAN AIR LAWS REQUIRE THE APPLICANT TO CONSIDER AVAILABLE CLEAN COAL TECHNOLOGY METHODS TO LOWER AIRBORNE CONTAMINANTS FROM IPP.

Integrated Gasification Coal Combustion (IGCC) and Circulating Fluidized Bed (CFB) are available, demonstrated cleaner coal combustion technologies with significant emission reduction benefits as compared to conventional PC boilers. But the permit application does not evaluate clean coal technology. Because IPP did not fully consider IGCC or CFB in its BACT analysis, Utah must direct the applicant to thoroughly evaluate these advanced combustion options as part of the BACT analysis. Indeed, the

IPSC 1377

state has a duty as part of the core of the BACT determination process to provide a reasoned justification for rejecting an available control technology.

Utah and Federal Law Require a Thorough Evaluation of IGCC and CFB Clean Coal Technologies as Part of the BACT Analysis.

Section 165(a)(4) of the Clean Air Act (CAA) provides that "no major emitting facility on which construction is commenced after August 7, 1977, may be constructed in any area to which this part applies unless…the facility is subject to the best available control technology for each pollutant subject to regulation under this chapter emitted from, or which results from, such facility."[1] The requirement for conducting a BACT analysis is codified at 40 CFR § 51.166(j), in regulations setting forth the requirements for state-administered PSD programs. Utah law, in turn, requires that an approval order may be issued only if "[t]he degree of pollution control for emissions, to include fugitive emissions and fugitive dust, is at least best available control technology. . ."[2]

BACT is then defined under Utah law as follows:

> [A]n emission limitation and/or other controls to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree of reduction of each pollutant subject to regulation under the Clean Air Act and/or Utah Air Conservation Act emitted from or which results from any emitting installation, which the Air Quality Board, on a case-by-case basis taking into account energy, environmental and economic impacts and other costs, determines is achievable for such installation through the application of production processes and available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant.[3]

The wording of the definition of BACT found within Utah's regulations is similar to the federal definition at 40 CFR § 51.166(b)(12). Indeed, Utah's definition of BACT must be consistent with the SIP requirements under federal regulations, which provide that "[a]ll State plans shall use the following definitions for the purposes of this section. Deviations from the following wording will be approved only if the State specifically demonstrates that the submitted definition is more stringent, or at least as stringent, in all respects" as the federal definitions.[4] Thus, the BACT requirement must be implemented and construed under Utah law at least as strictly as EPA and the federal courts have construed it.

EPA and federal courts have consistently interpreted the BACT provisions found in the CAA and the agency's regulations as embodying certain core criteria that require the

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[1] 42 U.S.C. §7475(a)(4).
[2] UT Air Quality Rules 307-401-6(1) (hereinafter "UT AQR").
[3] UT AQR 307-101-2.
[4] 40 CFR §51.166(b).

permit applicant either to implement the most effective available means for minimizing air pollution or justify its selection of less effective means on grounds consistent with the purposes of the Act. In *Citizens for Clean Air v. EPA*,[5] the Ninth Circuit held that "initially the burden rests with the PSD applicant to identify the best available control." As stated in long-standing EPA guidance, "[r]egardless of the specific methodology used for determining BACT, be it 'top-down,' 'bottom-up,' or otherwise, the same core criteria apply to any BACT analysis: the applicant must consider all available alternatives, and [either select the most stringent of them or] demonstrate why the most stringent should not be adopted."[6] Accordingly, the PSD permit applicant not only must identify all available technologies, including the most stringent, but it must also provide adequate justification for dismissing any available technologies.

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

> The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. This includes technologies employed outside of the United States. As discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.[7]

"The term 'available' is used…to refer to whether the technology 'can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term.'"[8] In keeping with the stringent nature of the BACT requirement, EPA has repeatedly emphasized that "available"

> is used in the broadest sense under the first step and refers to control options with a "practical *potential* for application to the

[5] 959 F.2d 839, 845 (9th Cir. 1992)

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

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

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

> emissions unit" under evaluation. . . . The goal of this step is to develop a comprehensive list of control options.[9]

EPA adjudicatory decisions also examine the core requirements for the BACT determination process. "Under the top-down methodology, applicants must apply the best available control technology unless they can demonstrate that the technology is technically or economically infeasible. The top-down approach places the burden of proof on the *applicant* to justify why the proposed source is unable to apply the best technology available."[10]

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

Thus, to conduct a BACT analysis consistent with the requirements of state and federal law, IPP must thoroughly evaluate all available control measures. Advanced coal combustion technologies -- including IGCC and CFB -- are commercially available today and would significantly reduce the volume of pollutants created by proposed new generating units, as discussed in detail below. Utah and federal law therefore require that these technologies be thoroughly evaluated as part of the BACT analysis.

Contrary to law, IPP does not consider these available methods, systems, and techniques in its BACT analysis but instead focuses exclusively on add-on pollution control technologies for pulverized coal units. The definitions of BACT under Utah and federal law, and the core requirements of the BACT analysis under federal case law, EPA adjudicatory decisions, and the New Source Review Manual, demonstrate that available techniques such as IGCC and CFB must be identified and evaluated as control options in the first step of the BACT analysis. These are minimum core requirements of a state-administered PSD program.

Recent State Actions Requiring Consideration of Clean Coal Technology Establish Irrefutable Precedence for the Consideration of IGCC and CFB.

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

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

Reflecting the viability of IGCC and CFB, the State of New Mexico issued a letter on December 23, 2002 requiring the permit applicant for a new coal-fired power plant to conduct a site-specific analysis of IGCC and CFB as part of the BACT analysis for the proposed facility: "The Department requires a site-specific analysis of IGCC and CFB in order to make a determination regarding BACT for the proposed facility." The New Mexico determination goes on to provide: "The analysis must include a discussion of the technical feasibility and availability of IGCC and CFB for the proposed site in McKinley County, including a discussion of existing IGCC and CFB systems."[11]

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

> Additional material must be provided in the BACT demonstration to address Integrated Gasification Coal Combustion (IGCC) as it is a 'production process' that can be used to produce electricity from coal. In this regard, the Illinois EPA has determined that IGCC qualifies as an alternative emission control technique that must be addressed in the BACT demonstration for the proposed plant. In addition, based on the various demonstration projects that have been completed for IGCC, the Illinois EPA believes that IGCC constitutes a technically feasible production process.
>
> Accordingly, Indeck must provide detailed information addressing the emission performance levels of IGCC, in terms of expected emissions rates and possible emission reductions, and the economic, environmental and/or energy impacts that would accompany application of IGCC to the proposed plant. This information must be accompanied by copies of relevant documents that are the basis of or otherwise substantiate the facts, statements and representations about IGCC provided by Indeck. In this regard, Indeck as the permit applicant is generally under an obligation to undertake a significant effort to provide data and analysis in its application to support the determination of BACT for the proposed plant.[12]

In an ensuing letter, the State of Illinois then formally informed EPA that Illinois has "concluded that it is appropriate for applicants for [proposed coal-fired power plants] to consider IGCC as part of their BACT demonstrations."[13]

Similarly, the Georgia Department of Natural Resources, in a March 2002 letter regarding the permit application of Longleaf Energy Station, also relied, in part, on the failure of the permit applicant to consider clean coal combustion technology in finding

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11 Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Corporation (Dec. 23, 2002). ATTACHMENT A.

12 Letter from Illinois Division of Air Pollution Control to Jim Schneider, Indeck-Elwood, LLC (March 8, 2003). ATTACHMENT B.

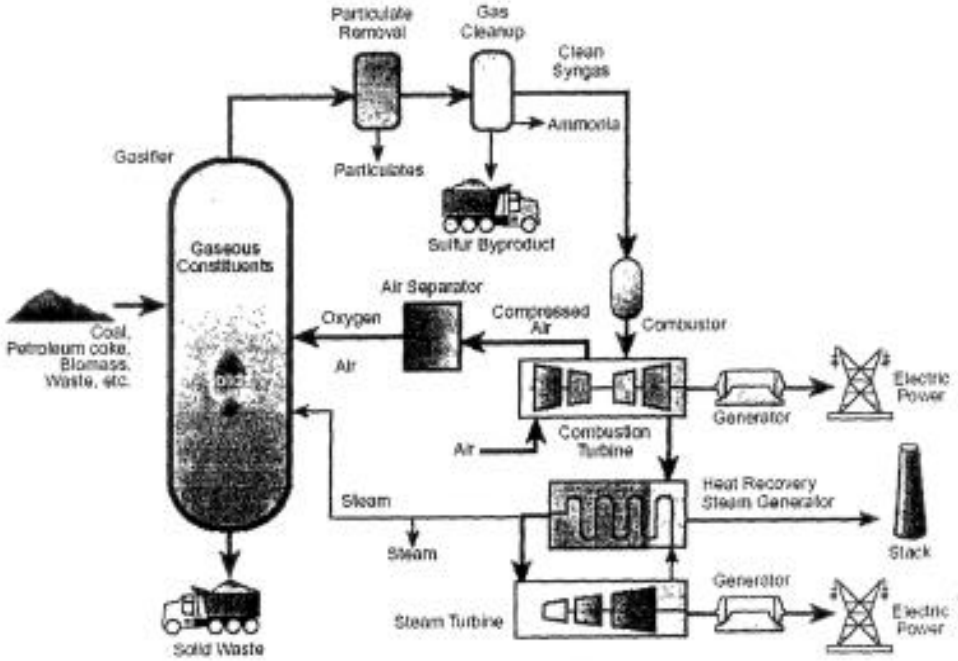
13 Letter from Illinois EPA Director to EPA Regional Administrator, Region V (March 19, 2003). ATTACHMENT B.

the application deficient. In making its determination of deficiency, Georgia stated that the applicant did not "discuss any other methods from generating electricity from the combustion of coal, such as pressurized fluidized bed combustion or integrated gasification combined cycle."[14] Georgia further stated that the applicant "should discuss these technologies and explain why you elected to propose a pulverized coal-fired steam electric power plant instead."[15]

IGCC Must be Considered in the BACT Analysis.

IGCC is an available method, system and technique for curbing air pollutants from IPP consistent with Utah's definition of BACT.[16]

Electricity generation from coal using IGCC technology is a commercially available and proven process. IGCC units generate electricity by integrating a coal gasifier with combined cycle (combustion turbine and steam turbine) electricity generation equipment (see figure below).



[14] Letter from James A. Capp, Manager, Stationary Source Permitting Program, Georgia DNR, to D. Blake Wheatley, Assistant Vice President, Longleaf Energy Associates, LLC (March 6, 2002). ATTACHMENT C.
[15] Id.
[16] UT AQR 307-101-2.

Two full scale commercial IGCC electric generating units are in operation in the United States: Tampa Electric Company's 262 MW unit at the Polk plant in Florida and Cinergy's 192 MW unit at the Wabash River plant in Indiana, which both rely on coal as a fuel source.[17] IGCC units can be constructed with multiple gasifiers to achieve unit availability at levels comparable to those of conventional baseload facilities. For instance, the Eastman Chemical plant in Kingsport, Tennessee has utilized a dual-gasifier design to produce chemicals from syngas and has experienced 98 percent availability since 1986.[18] ChevronTexaco claims that its new Standard Project Initiative Reference IGCC Plant achieves greater than 90% availability by using multiple gas trains.[19]

Worldwide there are 131 gasification projects in operation with a combined capacity equivalent to 23,750 MW of IGCC units.[20] An additional 31 projects are planned that would increase this capacity by more than 50 percent.[21] Although not all of these projects produce electricity from coal, they demonstrate widespread commercial application of gasification technology for fuel processing, one of two key components of an IGCC plant. The second component is a combined cycle electricity generating system, which is now commonplace for new natural gas fired power plants.

IGCC units are available from major well-known vendors. Coal gasification equipment is available from ChevronTexaco, Shell, and Global Energy, while major turbine manufacturers, including GE and Siemens-Westinghouse, provide combined cycle generators designed to run on the synthesis gas produced by coal gasifiers. Engineers from Texaco, Jacobs Engineering, and GE have teamed up to offer a standardized IGCC design.[22] James Childress, the Executive Director of the Gasification Technology Council, provided testimony to the U.S. Senate Environment and Public Works Committee stating, "[g]asification is a widely used commercially proven technology."[23] At the same hearing, Edward Lowe, Gas Turbine-Combined Cycle Product Line Manager for General Electric Power Systems, stated that, "IGCC is inherently less polluting and more efficient than any other coal power generation technology."[24] Likewise, the National Coal Council, in a May 2001 report, confirms that IGCC is "viable,

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[17] Resource Systems Group, Inc., EPIndex. See www.epindex.com

[18] Smith, R.G., "Eastman Chemical Plant Kingsport Plant Chemicals from Coal Operations,1983-2000," 2000 Gasification Technologies Conference.

[19] O'Keefe, L. and Sturm, K., "Clean Coal Technology Options – A Comparison of IGCC vs. Pulverized Coal Boilers," presentation to the 2002 Gasification Technologies Conference, October 2002

[20] Simbeck, Dale, SFA Pacific Inc. Gasification Technology Update, presented to the European Gasification Conference, April 8-10, 2002. The total capacity is based on output of synthesis gas. Many of these projects produce chemicals in addition to or instead of electricity.

[21] Id.

[22] O'Keefe, Luke, et al. A Single IGCC Design for Variable CO_2 Capture.

[23] Childress, James M. Statement Submitted for the Record, Senate Environment and Public Works Subcommittee on Clean Air, Wetlands and Climate Change, January 29, 2002.

[24] Lowe, Edward. *Outlook on Integrated Gasification Combined Cycle (IGCC) Technology*. Senate Environment and Public Works Subcommittee on Clean Air, Wetlands and Climate Change, January 29, 2002.

commercially available technology."[25] ChevronTexaco, in an October 2002 presentation, states that, "IGCC is a current viable choice for clean coal capacity."[26] And the Center for Energy and Economic Development (CEED) states that, "IGCC technology is available for deployment today."[27]

IGCC's Environmental Performance is Superior to other Technologies for Generating Electricity from Coal.

The coal gasification fuel-processing step in IGCC power plants results in superior environmental performance. Gasifying coal at high pressure prior to combustion facilitates removal of pollutants that would otherwise be released into the air. According to James Childress, "...criteria pollutant emissions for a coal-based IGCC plant are well below those of even the most modern pulverized coal plants with post combustion cleanup."[28]

Criteria pollutants for a coal-based IGCC are below those of even the most modern pulverized coal plants with additional controls. NOx emissions are approximately half those of modern pulverized coal plants without any post-combustion controls. Sulfur is also removed from the syngas in pre-combustion cleanup so that emissions are less than half of state-of-the-art conventional coal plants. Particulate emissions are also reduced by 99.9 percent using IGCC technology relative to conventional coal technologies.

IGCC also has several other environmental advantages beyond its reductions in criteria pollutants. Mercury and CO_2 removal is easier and less expensive at IGCC units than at other coal-fired plants. Because an IGCC plant is typically 10 to 15 percent more efficient in terms of heat rate than a conventional sub-critical pulverized coal plant, carbon dioxide (CO2) emissions -- the primary greenhouse gas responsible for anthropogenic contributions to global warming -- are also reduced by that same amount. In addition, the concentrated CO2 in the pre-combustion gas stream can be captured and sequestered at a fraction of the cost of post-combustion carbon capture and sequestration at a conventional coal plant. The reduced CO_2 emissions rate has important environmental benefits in addressing the urgent problem of global climate change and also reduces increased costs due to future climate change regulations.

Furthermore, mercury removal rates of up to 90 percent can also be achieved using currently available control technologies with IGCC. DOE states that "an IGCC power plant has the potential of achieving very high mercury removal performance with established technology" and mercury removal in an IGCC power plant can be expected to

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[25] National Coal Council, Increasing Electricity Availability from Coal-Fired Power Plants in the Near Term, p. 20 (May 2001).
[26] "Clean Coal Technology Options – A Comparison of IGCC vs. Pulverized Coal Boilers," Luke O'Keefe and Karl Sturm (ChevronTexaco), October 28, 2002, p. 8. ATTACHMENT D.
[27] See www.ceednet.org/fueling/investing.asp
[28] Childress, James M. Statement Submitted for the Record, Senate Environment and Public Works Subcommittee on Clean Air, Wetlands and Climate Change, January 29, 2002.

be very high in removal effectiveness, low in cost, and reliable in design."[29] DOE indicates that when comparing IGCC to PC boilers, "the cost of removal of mercury by a carbon bed in an IGCC plant is lower than in a pulverized coal (PC) plant."[30] In a direct comparison of costs, mercury removal in an IGCC facility is estimated to be $3,412 per pound whereas in a PC system (90% removal in a 975MW plant) the costs are estimated to be $37,800 per pound.[31]

Also, the vitrified solid waste created by IGCC has a number of marketable uses, thereby potentially reducing some of the solid waste disposal issues associated with coal combustion using conventional technologies.

The Wabash River facility's SO2 emissions are consistently below 0.10 lb/mmBtu and are reaching as low as 0.03 lb/mmBtu.[32] In addition, on March 26, 2002, the Ohio EPA issued a final permit for the Lima Energy project, a 580 MW IGCC facility consisting of two 290 MW combined cycle turbines. In June 2001, Kentucky issued a permit for Kentucky Pioneer. The Lima and Kentucky facilities are permitted to accept coal, and Lima can accept petroleum coke and refuse-derived fuel. Furthermore, in June 2002, Wisconsin Electric Power Company applied to the Wisconsin Department of Natural Resources for air permits for two supercritical pulverized coal units and one IGCC unit at the Elm Road site in Oak Creek, Wisconsin. The IGCC unit will be 615 MW.[33] Table 1 below summarizes the relevant emissions.

	Emission Rates (lb/mmBtu)			
Pollutant	IPP	Kentucky Pioneer (1)	Lima (1)	Elm Road (2)
S02	0.10	.032	.021	0.03
NOx	0.07	.074	.097	0.07
PM	0.015	.011	.01	0.011

(1) Permit limits written in terms of maximum lb/hr. The lb/mmBtu rate estimated from maximum heat input to the plant.
(2) Elm Road is not a permit level, but the level proposed by the company to state regulators.

As the current permitting actions for the Kentucky Pioneer, Lima Energy and Elm Road facilities demonstrate, IGCC is a cleaner technology.[34]

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[29] "The Cost of Mercury Removal in an IGCC Plant," US DOE, NETL, September 2002 at 1-2.
[30] "The Cost of Mercury Removal in an IGCC Plant," US DOE, NETL, September 2002 at 1-2.
[31] Id.
[32] See www.lanl.gov/projects.cctc/factsheets/wabsh/wabashrdemo.html
[33] Both the Lima Energy and Elm Road projects were designed to utilize either Ohio coals (Lima) or eastern bituminous coals (Elm Road). Coal gasification, however, is a flexible technology that can be designed for western coals.
[34] See also "Clean Coal Technology Options – A Comparison of IGCC vs. Pulverized Coal Boilers," Luke O'Keefe and Karl Sturm (ChevronTexaco), October 28, 2002, p. 30-42. ATTACHMENT D.

Utah Chapter Sierra Club
Wasatch Clean Air Coalition
Grand Canyon Trust
Rocky Mountain Office of Environmental Defense
Western Resource Advocates
Clean Air Task Force

May 20, 2004

By e-mail (milkar@utah.gov), Fax (801) 536-4099, and Federal Express
Milka M. Radulovic, Engineer
Utah Department of Environmental Quality
Richard W. Sprott
Director, Utah Division of Air Quality
150 North 1950 West
Salt Lake City, Utah 84116

Re: Comments on Intent to Approve PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station, DAQE-IN0327010-04

Dear Ms. Radulovic and Mr. Sprott:

The Utah Chapter of the Sierra Club, Wasatch Clean Air Coalition, Rocky Mountain Office of Environmental Defense, Western Resource Advocates, Grand Canyon Trust, and Clean Air Task Force, respectfully provide the following comments on Utah Division of Air Quality's ("UDAQ") draft Intent to Approve ("ITA" or "draft permit") PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station, DAQE-IN0327010-04. On April 14, 2003, we submitted extensive comments on Intermountain Power Service Corporation's (IPSC) December 2002 prevention of significant deterioration (PSD) permit application. For the most part, none of the comments we raised were adequately addressed by UDAQ in the ITA for proposed Unit 3 at the Intermountain Power Plant (IPP). A copy of that letter and attachments is attached and incorporated herein by reference to this letter. We have also identified other issues with the ITA that need to be addressed to comply with state and federal law. In summary, we believe it would be contrary to law and harmful to Utah's air quality for the UDAQ to approve the proposed construction of this facility without first addressing the serious deficiencies examined in detail below. We greatly appreciate your consideration of our views and UDAQ's efforts to make documents regarding this action easily available to interested parties. We would greatly appreciate being promptly notified of any subsequent action on this ITA, including issuance of any final Approval Order.

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IPSC 2349

IPSC FAILED TO SUBMIT A COMPLETE PERMIT APPLICATION AND THUS CONSIDERATION OF THE PERMIT APPLICATION IS PREMATURE

IPSC failed to submit a complete permit application. Instead, IPSC submitted an "incomplete" application for public comment that it proposes to "fix" later. See 6/12/03 email from Sprott to LeBaron (attached). IPP's permitting strategy is illegal because it denies the public of a full opportunity to comment on all aspects of the permit application before a final permit is issued.

Further, the administrative record indicates that UDAQ is unable to assess important aspects of the permitting requirements because a boiler design has not been selected. More specifically, IPP admits that "the LOI content in the fly ash anticipated from Unit 3 cannot be predicted until a final boiler design is selected." See, 7/28/03 letter from IPA to UDAQ, p. 10. No permit should be issued until this can be quantified with certainty.

Moreover, IPSC has failed to identify, with any specificity, the coal type or coal quality to be burned at Unit 3. In fact, IPP's description of coal type and coal quality is conflicting and vague and thus it would be arbitrary and capricious for UDAQ to approve a final permit until this important aspect of the permit is specified. For example, for some emissions, like mercury, IPSC proposes to look at the range of coals that IPP Unit 3 will be designed to burn over the life of the plant (i.e., bituminous and subbituminous). See, 7/28/03 letter from IPA to UDAQ, p. 3 & 4. The range of mercury content of the coal (.02 ppm by weight to .15 ppm) provided by IPP is too broad and vague to be relied upon. Moreover, in the Technical Memorandum, it states that IPSC will only burn western bituminous coals. See, 9/8/03 Technical memorandum from CH2M Hill to UDAQ, p. 1. This is inconsistent with other statements in the administrative record. No final permit should be issued until IPP provides specific information on coal type and coal quality.

Finally, the draft permit is fatally flawed because it fails to contain specific coal quality requirements or a coal blending requirement to ensure all emission limits will be met. An earlier draft of the permit contained a percentage blending limit but was wrongfully eliminated from the permit at the urging of IPSC. See, March 1, 2004 draft permit from Radulovic, p. 156, condition 7.A. (attached) and 3/8/04 email from Sands to Radulovic (attached). It appears that IPSC is thwarting any attempt to identify with certainty the type and quality of the coal to be burned at Unit 3. It is essential that the final permit contain an enforceable coal quality/blending requirement to ensure that short term emission limits are met as well as other permit conditions. See, 2/5/03 email from Orth to Prey (attached) and 7/8/03 memo from Radulovic to Sands (attached).

IGCC MUST BE ADEQUATELY CONSIDERED AND IPSC'S IGCC BACT ANALYSIS IS FLAWED

FEDERAL AND STATE CLEAN AIR LAWS REQUIRE IPSC TO CONSIDER THE APPLICATION OF PRODUCTION PROCESSES AND AVAILABLE METHODS, SYSTEMS AND TECHNIQUES TO LOWER AIRBORNE CONTAMINANTS.

Integrated Gasification Combined Cycle (IGCC) is an available, demonstrated clean coal combustion technology with significant emission reduction benefits. There are numerous benefits to IGCC, including fewer emissions of criteria and hazardous air pollutants, the opportunity for capturing greenhouse gases, such as CO_2, that cause global warming, and a general increase in efficiency over other coal burning technologies. Because IPP's evaluation of IGCC is so flawed, UDAQ must deny the proposed permit. A properly conducted top-down BACT analysis, as follows in these comments, shows IGCC is BACT at the IPP site

Utah and Federal Law Require a Thorough Evaluation of IGCC Cleaner Coal Combustion Technology as Part of the BACT Analysis.

Section 165(a)(4) of the Clean Air Act (CAA) provides that "no major emitting facility on which construction is commenced after August 7, 1977, may be constructed in any area to which this part applies unless…the facility is subject to the best available control technology for each pollutant subject to regulation under this chapter emitted from, or which results from, such facility."[1] The requirement for conducting a BACT analysis is codified at 40 CFR § 51.166(j), in regulations setting forth the requirements for state-administered PSD programs. Utah law, in turn, requires that an approval order may be issued only if "[t]he degree of pollution control for emissions, to include fugitive emissions and fugitive dust, is at least best available control technology. . ."[2]

BACT is then defined under Utah law as follows:

> [A]n emission limitation and/or other controls to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree of reduction of each pollutant subject to regulation under the Clean Air Act and/or Utah Air Conservation Act emitted from or which results from any emitting installation, which the Air Quality Board, on a case-by-case basis taking into account energy, environmental and economic impacts and other costs, determines is achievable for such installation through the application of production processes and available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant.[3]

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[1] 42 U.S.C. §7475(a)(4).
[2] UT Air Quality Rules 307-401-6(1) (hereinafter "UT AQR").
[3] UT AQR 307-101-2.

The wording of the definition of BACT found within Utah's regulations is similar to the federal definition at 40 CFR § 51.166(b)(12). Indeed, Utah's definition of BACT must be consistent with the SIP requirements under federal regulations, which provide that "[a]ll State plans shall use the following definitions for the purposes of this section. Deviations from the following wording will be approved only if the State specifically demonstrates that the submitted definition is more stringent, or at least as stringent, in all respects" as the federal definitions.[4] Thus, the BACT requirement must be implemented and construed under Utah law at least as strictly as EPA and the federal courts have construed it.

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

> Mr. HUDDLESTON. Mr. President, the proposed provisions for application of best available control technology to all new major emission sources, although having the admirable intent of achieving consistently clean air through the required use of best controls, if not properly interpreted may deter the use of some of the most effective pollution controls. The definition in the committee bill of best available control technology indicates a consideration for various control strategies by including the phrase "through application of production processes and available methods systems, and techniques, including fuel cleaning or treatment." And I believe it is likely that the concept of BACT is intended to include such technologies as low Btu gasification and fluidized bed combustion. But, this intention is not explicitly spelled out, and I am concerned that without clarification, the possibility of misinterpretation would remain. It is the purpose of this amendment to leave no doubt that in determining best available control technology, all actions taken by the fuel user are to be taken into account--be they the purchasing or production of fuels which may have been cleaned or up-graded through chemical treatment, gasification, or liquefaction; use of combustion systems such as fluidized bed combustion which specifically reduce emissions and/or the post-combustion treatment of emissions with cleanup equipment like stack scrubbers. The purpose, as I say, is just to be more explicit, to make sure there is no chance of misinterpretation. Mr. President, I believe again that this amendment has been checked by the managers of the bill and that they are inclined to support it.
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> Mr. MUSKIE. Mr. President, I have also discussed this amendment with the distinguished Senator from Kentucky. I think it has been worked out in a form I can accept. I am happy to do so. I am willing to yield back the remainder of my time.[5]

EPA and federal courts have consistently interpreted the BACT provisions found in the CAA and the agency's regulations as embodying certain core criteria that require the

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[4] 40 CFR §51.166(b).

[5] 95th Congress, 1st Session (Part 1 of 2) June 10, 1977 Clean Air Act Amendments of 1977 A&P 123 Cong. Record S9421.

permit applicant either to implement the most effective available means for minimizing air pollution or justify its selection of less effective means on grounds consistent with the purposes of the Act. In *Citizens for Clean Air v. EPA*,[6] the Ninth Circuit held that "initially the burden rests with the PSD applicant to identify the best available control." As stated in long-standing EPA guidance, "[r]egardless of the specific methodology used for determining BACT, be it 'top-down,' 'bottom-up,' or otherwise, the same core criteria apply to any BACT analysis: the applicant must consider all available alternatives, and [either select the most stringent of them or] demonstrate why the most stringent should not be adopted."[7] Accordingly, the PSD permit applicant not only must identify all available technologies, including the most stringent, but it must also provide adequate justification for dismissing any available technologies.

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

> The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. This includes technologies employed outside of the United States. As discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.[8]

"The term 'available' is used…to refer to whether the technology 'can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term.'"[9] In keeping with the stringent nature of the BACT requirement, EPA has repeatedly emphasized that "available"

> is used in the broadest sense under the first step and refers to control options with a "practical *potential* for application to the emissions unit" under evaluation. . . . The goal of this step is to develop a comprehensive list of control options.[10]

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[6] 959 F.2d 839, 845 (9th Cir. 1992).

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

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

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

[10] In re: Knauf Fiber Glass, PSD Appeal Nos. 98-3 – 98-20 (EAB February 4, 1999), at 12-13 (quoting NSR Manual at B.5) (emphasis added by EAB); see also In re: Steel Dynamics, Inc., PSD Appeal Nos. 99-

EPA adjudicatory decisions also examine the core requirements for the BACT determination process. "Under the top-down methodology, applicants must apply the best available control technology unless they can demonstrate that the technology is technically or economically infeasible. The top-down approach places the burden of proof on the *applicant* to justify why the proposed source is unable to apply the best technology available."[11]

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

Thus, to conduct a BACT analysis consistent with the requirements of state and federal law, UDAQ and IPP must thoroughly evaluate all available control measures. IGCC is available today. Utah and federal law therefore require that IGCC be thoroughly evaluated as part of the BACT analysis.

Contrary to law, IPP does not properly consider this available method, system, and technique in its BACT analysis because of fundamental flaws in the analysis. The definitions of BACT under Utah and federal law, and the core requirements of the BACT analysis under federal case law, EPA adjudicatory decisions, and the New Source Review Manual, demonstrate that an available technique such as IGCC must be identified and evaluated as a control option in the first step of the BACT analysis. These are minimum core requirements of a state-administered PSD program.

Recent State Actions Requiring Consideration of IGCC Establish Irrefutable Precedence for the Consideration of IGCC.

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

> Additional material must be provided in the BACT demonstration to address Integrated Gasification Coal Combustion (IGCC) as it is a `production process' that can be used to produce electricity from coal. In this regard, the Illinois EPA

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4 and 99-5 (EAB June 22, 2000), at 29 n.24 (citing Knauf with approval); NSR Manual at B.10 ("The objective in step 1 is to identify all control options with potential application to the source and pollutant under evaluation."); id. at B.6 (emphasizing that a proper Step 1 list is "comprehensive").

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

> has determined that IGCC qualifies as an alternative emission control technique that must be addressed in the BACT demonstration for the proposed plant. In addition, based on the various demonstration projects that have been completed for IGCC, the Illinois EPA believes that IGCC constitutes a technically feasible production process.
>
> Accordingly, Indeck must provide detailed information addressing the emission performance levels of IGCC, in terms of expected emissions rates and possible emission reductions, and the economic, environmental and/or energy impacts that would accompany application of IGCC to the proposed plant. This information must be accompanied by copies of relevant documents that are the basis of or otherwise substantiate the facts, statements and representations about IGCC provided by Indeck. In this regard, Indeck as the permit applicant is generally under an obligation to undertake a significant effort to provide data and analysis in its application to support the determination of BACT for the proposed plant.[12]

In an ensuing letter, the State of Illinois then formally informed EPA that Illinois has "concluded that it is appropriate for applicants for [proposed coal-fired power plants] to consider IGCC as part of their BACT demonstrations."[13]

Reflecting the viability of IGCC, the State of New Mexico issued a letter on December 23, 2002 requiring the permit applicant (Mustang Energy a subsidiary of Peabody Coal Company) for a proposed new pulverized coal power plant to conduct a site-specific analysis of IGCC as part of the BACT analysis for the proposed facility: "The Department requires a site-specific analysis of IGCC and CFB in order to make a determination regarding BACT for the proposed facility." The New Mexico determination goes on to provide: "The analysis must include a discussion of the technical feasibility and availability of IGCC and CFB for the proposed site in McKinley County, including a discussion of existing IGCC and CFB systems."[14]

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

> Mustang concludes that neither IGCC nor CFB are technically feasible control options for the Mustang site. After careful review of the revised BACT analysis, as well as information gathered from independent sources, the Department determines that Mustang's conclusion is not supported by the evidence. Accordingly, the Department finds that Mustang has not demonstrated the

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[12] Letter from Illinois Division of Air Pollution Control to Jim Schneider, Indeck-Elwood, LLC (March 8, 2003), attached hereto.

[13] Letter from Illinois EPA Director to EPA Regional Administrator, Region V (March 19, 2003), attached hereto.

14 Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Company (Dec. 23, 2002), attached hereto.

technical infeasibility of IGCC and CFB. Moreover, applying the criteria in the NSR Manual, the Department determines that IGCC and CFB are technically feasible at the Mustang site, and must be evaluated in the remaining steps of the top down BACT methodology.

(a) IGCC and CFB are technically feasible at the Mustang site. A technology is considered to be technically feasible if it is commercially available and applicable to the source under consideration. *See* NSR Manual at B.17-18. A technology is commercially available if it has reached a licensing and commercial sales stage of development. *Id.* A technology is applicable if it has been specified in a permit for the same or a similar source type. *Id.* Mustang's revised BACT analysis indicates that IGCC is commercially available, and IGCC has been specified in air quality permits for coal-fired power plants. *See, e.g.,* Lima Energy Facility, 580 megawatt coal-fired power plant. Similarly, CFB is commercially available and has been specified in air quality permits for coal-fired power plants. *See, e.g.,* AES Puerto Rico 454 megawatt coal-fired power plant; Reliant Energy Seward 584 megawatt coal-fired power plant.

(b) For both IGCC and CFB, Mustang improperly relies on cost to determine technical infeasibility. A technology is technically feasible when the resolution of technical difficulties is a matter of cost. *See* NSR Manual at B.19-20. Mustang's revised BACT analysis indicates that the resolution of technical difficulties for both IGCC and CFB are a matter of cost. These costs do not support a finding of technical infeasibility, but may be considered during Step 4 of the top down BACT methodology. *See* NSR Manual at B.26.[15]

It would be arbitrary and capricious were Utah not to likewise require consideration of IGCC as BACT. The December 2002 and August 2003 New Mexico determinations and the March 2003 Illinois determination are attached hereto.

Attached is a memorandum from Vickie Patton of Environmental Defense and Joro Walker of Western Resource Advocates explaining the legal basis for requiring consideration of IGCC in the BACT analysis, which was previously provided to your office.

IPP Failed to Correctly Address IGCC in the BACT Analysis and the Permit Must be Denied. A Properly Conducted BACT Analysis Shows IGCC is BACT for the IPP Project.

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[15] Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Company (Aug. 29, 2003), at p. 3, attached hereto.

Appendix I-8 of the NOI contains a top-down BACT analysis which compares the proposed PC plant to both CFB and IGCC plants of similar size. The analysis contains fundamental flaws in both methodology and assumptions, and some significant math errors. These flaws greatly overstate both the cost and the tons of pollutants emitted by IGCC. These errors are compounded by an improper method of calculating incremental costs which, when taken together with the other errors, overstate the incremental costs of pollution removed by the IGCC plant by two orders of magnitude. The main problems with Appendix I-8 are summarized below.

1. The heat rate for IGCC is incorrectly increased for altitude.
   The IGCC heat rate assumed in Appendix I-8 is to be 10,800 Btu/Kw. IPP calculates the heat rate by taking the heat rate for the Polk plant (built in the mid-1990s) and increasing it by 12% to account for derating of the combustion turbines due to the plant site's altitude of 4600 ft MSL.[16] This approach is fundamentally wrong. Attached hereto is a General Electric Gas Turbine Altitude Correction Curve chart that shows how to derate the turbine with altitude. The "notes" to the chart state that the turbine's heat rate does not change with altitude. Conversations with ConocoPhillips confirm that altitude does not change the heat rate of the turbine nor the gasification island to any significant degree.[17] The reason: while there is less oxygen at altitude causing the turbine to produce fewer Kw of electricity relative to sea level, the amount of heat input into the turbine also decreases, and so the overall heat rate stays the same.

   IGCC plants have higher cost of electricity at altitude relative to the same plant at sea level because of both higher Air Separation Unit costs and turbine derating, but these costs must be accounted for differently.

   The appropriate heat rate for an IGCC plant should be what vendors are able to guarantee today, not historic numbers from when Polk Florida was built in the 1990s. For ConocoPhillips E-Gas technology, the heat rate today is around 8637 Btu/Kw. This, or comparable value, is what IPP should have used for the IGCC heat rate in Appendix I-8.

   As a result of using an incorrect heat rate, IPP significantly overstates the costs and emissions from an IGCC unit.

2. IPP uses outdated capital costs for the IGCC plant.
   Appendix I-8 uses the cost of the Polk IGCC plant, built in the early 1990s, to estimate the capital cost of an IGCC plant. This approach fails to account for the

[16] NOI, Appendix I-8, Table 11, page II-21.
[17] Personal Communication between John Thompson CATF and Cliff Keeler of ConocoPhillips, May 18, 2004.

decreased costs of an IGCC plant today. Since Polk was built, numerous IGCC plants have been built at refineries, driving down the cost of IGCC plants in general. A better approach is to use recent cost studies from organizations like EPRI, who undertake detailed cost studies of both PC and IGCC plants for public and private clients. Attached hereto are Tables 16-1 and Table 16-2 from an EPRI report entitled, "Phased Construction of IGCC Plants for CO2 Capture- Effect on Pre-investment." The tables detail costs for a 509 MW net IGCC plant in a New York location without carbon capture. Even after accounting for altitude differences, costs for an IGCC plant of the size required by IPP would only be about $1.1 billion, not the $1.7 billion used by IPP based upon outdated Polk costs.

Reducing the capital costs of the IGCC in Appendix I-8 would significantly lower the annualized costs used in the BACT calculation.

As described later in this document, the Appendix also overstates O & M costs.

3. Annual operating costs calculated in Appendix I-8 for the PC contain a math error that significantly understates costs.
   Appendix I-8 calculates the annual operating costs for the PC in Part II, Appendix B. The relevant table is attached hereto. (7/26/03 Sargent & Lundy, "Part II-PC/CFB/IGCC BACT Determination". The indirect cost category has three items, each equaling $11,080,000, labeled "Property Taxes, Insurance and Administration." However, only two of these three items are actually added to the annual costs for the top-down BACT analysis. As a result, the PC costs are reported as $168,503,000 instead of $179,583.000.[18]

4. The availability of an IGCC plant should be assumed to be over 90% when a spare gasifier is added.
   Appendix I-8 Method states that no IGCC plant has a demonstrated availability above 80%. This conclusion overlooks two facts: 1) the Polk and Wabash IGCC units are only single train gasifiers that have no spare, and 2) Spare gasifiers increase availability to over 90%. Eastman Chemical operates a chemical plant where two gasifiers are used, including a spare. The availability of the gasification operation is over 98%.

5. Appendix I-8 does not accurately capture the values for actual IGCC emissions or recent permit levels for IGCC.
   Appendix I-8 overstates the emissions from IGCC plants. After Appendix I-8 was completed, Wisconsin DNR issued a permit for both SCPC and IGCC units at Elm

[18] The actual costs of the PC for the purposes of the BACT calculation may be closer to $200,000,000/yr. The fixed O&M values for the PC plant may be greatly underestimated. IPP shows these costs to be about $8 /KW-year. In contrast, nationwide, EIA's Annual Energy Outlook -- 2003 projects Fixed Operating and Maintenance costs on new scrubbed plants at $24.52 per kW-year. See Annual Energy Outlook 2003, DOE/EIA-0554(2003), January 2003, page 73.

technology risk of using IGCC is small in comparison to the challenge of the overall financial risks of building any large coal project. As Table 3 shows the economics of IGCC are not that different from a PC.

Step 5. Select BACT

Conclusion: IGCC is BACT for the IPP Project.

UDAQ AND IPSC SHOULD HAVE CONSIDERED A SUPERCRITICAL PULVERIZED COAL BOILER FOR THE NEW UNIT

UDAQ and IPSC should have also considered the construction of a supercritical pulverized coal boiler, rather than the planned subcritical pulverized coal boiler. Supercritical boilers are up to 7% or more efficient than subcritical boilers. Thus, supercritical boilers use less fuel and emit less carbon dioxide emissions. Further, such supercritical boilers achieve up to 17% lower emission rates of carbon monoxide (CO), nitrogen oxides (NOx) and sulfur oxides (SOx), as well as up to 15% lower PM emission rates.[41] For example, Steag has recently submitted a PSD permit application to the U.S. EPA for a supercritical boiler that would achieve an emission limit for SO2 of .06 lbs/MMbtu on a 30 day rolling average (attached). This SO2 emission limit is significantly lower than that being proposed by IPP and can be attributed at least in part to the employment of a supercritical boiler. Xcel Energy is also considering the construction of a supercritical boiler for new proposed unit at its Comanche plant in Pueblo, Colorado.

Thus, UDAQ and IPSC should have evaluated the installation of a supercritical boiler at IPP Unit 3 as an inherently lower emitting process as part of its BACT determination.

THE ITA FAILS TO ADDRESS CARBON DIOXIDE AND OTHER GREENHOUSE GAS EMISSIONS

The ITA for IPP Unit 3 did not address carbon dioxide (CO_2) or other greenhouse gases to be emitted from the new unit. However, such emissions can be quite significant from coal-fired boilers.

We believe that the EPA, and the State of Utah have a legal obligation to regulate CO_2 and other greenhouse gases as pollutants under the Clean Air Act and the Utah Air Conservation Act. Indeed, twelve states, fourteen environmental groups and two cities have filed suit in federal court stating that EPA must regulate greenhouse gas emissions under the Clean Air Act. Specifically, the parties appealed the U.S. EPA's decision to reject a petition that sought to have the federal government regulate greenhouse gas

[41] See attached presentation by Tom Bartolomei, ALSTOM, *Sliding Pressure Supercritical Boilers: Flexible and Efficient Technology for New Coal-Fired Generation*, presented at COAL-GEN, August 1, 2002.

emissions from new motor vehicles.[42] If the federal court agrees that greenhouse gases, such as CO_2, must be regulated under the Clean Air Act, such a decision would also require the establishment of CO_2 emission limits in this permit for IPP Unit 3.

At the minimum, UDAQ must consider emissions of CO2 in its BACT analysis for IPP Unit 3. The federal Environmental Appeals Board (EAB) has interpreted the definition of BACT as requiring consideration of unregulated pollutants in setting emission limits and other terms of a permit, since a BACT determination is to take into account environmental impacts.[43] Attached is a recently issued paper entitled *Considering Alternatives: The Case for Limiting CO2 Emissions from New Power Plants through New Source Review* by Gregory B. Foote that discusses the regulatory background to support consideration of CO2 impacts when permitting a new source and, in particular, a new coal-fired power plant. This paper indicates that it is entirely appropriate to consider CO2 emissions when evaluating environmental impacts under the new source review permit program, and the paper also provides suggested approaches for evaluating technologies in terms of CO2 emissions.

Similarly, Utah state law also supports regulation of greenhouses gases under the minimum federal requirements and state law. The purposes of the Utah Air Conservation Act is to "provide for a coordinated statewide program for air pollution prevention, abatement, and control." Utah Code Ann. § 19-2-101(4)(a). The term air pollution "means the presence in the ambient air of one or more air contaminants in such quantities and duration and under conditions and circumstances, as is or tends to be injurious to human health or welfare, animal or plant life, or property, or would unreasonable interfere with the enjoyment of life or use of property as determined by the standards, rules, and regulations adopted by the Air Quality Board (Section 19-2-104)." Utah Admin. Rule R307-101-2; Utah Code Ann. § 19-2-102. The State of Utah Division of Air Quality has recognized that "the consensus of most scientists worldwide is that increasing concentrations of greenhouse gases will lead to significant climate warming, shifts in precipitation patterns, and rising sea levels, although the magnitude, timing, and regional patterns of these changes cannot be accurately predicted at this time." Utah Division of Air Quality, *Greenhouse Gas Inventory-1990 and 1993,* available at www.airquality.utah.gov/PLANNING/Grnhsgas.htm. Accordingly, existing state legal authority supports the regulation of greenhouses gases by UDAQ in this permit.

UDAQ AND IPSC SHOULD HAVE EVALUTED THE USE OF K-FUELS

The UDAQ failed to evaluate the use of K-Fuels at IPP Unit 3 as an option for inherently lower criteria pollutant emissions as well as mercury emissions. K-fuel is coal that is treated by a pre-combustion process that improves the quality of the coal, increasing the heat content of the coal, and removing some of the sulfur and NOx precursors as well as mercury. The first K-fuel production plant is being built at the Black Thunder Mine in

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[42] Commonwealth of Massachusetts, et al. v. U.S. EPA, No. 03-1361 (Consolidated with Nos. 03-1362-1368) U.S. Court of Appeals for the District of Columbia Circuit.

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

Mercury (Hg):

Mercury is a natural trace constituent of coal. Depending on the source of the coal the mercury content of the coal may vary. MidAmerican intends to use Powder River Basin coal in CBEC Unit #4. Coal analyses for selected Powder River Basin coals were submitted by MidAmerican in a response dated December 26, 2002. These analyses show that the maximum mean mercury content from any source is 0.1 ppmw. The annual average mercury content should be below this number. However, because there are multiple sources of coal and it is not known how much coal will be received from each of these sources, it is impossible to predict an accurate value for the annual average mercury content. Therefore, the annual emissions of 0.34 tons per year were determined using 0.1 ppmw mercury. This is the average mercury concentration reported from the Wyodak mine.

The results of a review of the population of electric utility steam generating units showed that there were currently no units that have installed and are continuously operating any control system specifically for the removal of mercury from the exhaust gases. However, the control equipment employed to remove other pollutants like SO_2 and PM/PM_{10} does remove some of the mercury from the exhaust gas. The available data on mercury removal is limited. USEPA has required several units to perform sampling to determine the mercury emissions from coal fired boilers. This data is available to the public on USEPA's website at http://www.epa.gov/ttn/atw/combust/utiltox/icrdata.xls. This data set is referred to as the ICR data. There are a couple of flaws in this data set. First, the data only represents one-time emissions sampling data. The results would represent what was being achieved at that moment in time. However, it appears that coal chemistry, chlorine content specifically, does affect the ability of existing control equipment to remove mercury from exhaust streams. The ICR data does not address the coal variability at any given site. Furthermore, the results from several of the facilities show negative reductions in emissions. In other words, the emissions of mercury out the control equipment were greater than the emissions out of the furnace. Based on these two points, the Department has concluded that the ICR data does not sufficiently address the emissions limitations that are achieved in practice by other units. Therefore, the Department will not use this information in determining a MACT floor emission rate. Since there are no existing units operating with control specifically for mercury control, but rather are simply removing mercury as a co-benefit to the control of SO_2 and PM/PM_{10}, the Department has concluded that the co-benefits from the SO_2 and PM/PM_{10} control is the MACT floor.

One technology has been identified as a potential beyond-the-floor control for mercury. That technology is sorbent injection. To date, the only commercially available system uses activated carbon as the sorbent injected in the system. However, research continues on other materials that could be used as sorbents in an injection system to remove mercury. The applicant has agreed to install a sorbent injection system to remove the mercury from the exhaust of this unit. For purposes of this review, the Department will consider the system to be using activated carbon as the sorbent. The applicant would like to have the ability to explore other materials should they become commercially available before the unit begins operation. The permit allows for an optimization study of the system. The type of sorbent used will be evaluated during this test period. Several field tests have been completed at different facilities to determine the efficiency of sorbent injection systems on the removal of mercury. Unfortunately, in

Considering Alternatives: The Case for Limiting CO2 Emissions from New Power Plants Through New Source Review

by Gregory B. Foote, Assistant General Counsel,
U.S. Environmental Protection Agency

The author is presently detailed to the Center for International Environmental Law (CIEL) in Washington, D.C. The views expressed in this Article and explanatory materials are solely those of the author and do not reflect the position of EPA or CIEL.

Expanded Outline

INTRODUCTION

For the first time in decades, power companies are planning to build large numbers of new coal-fired plants in the United States. Under business as usual, these plants – the largest emitters of greenhouse gases (they make up 1/3 of total U.S. CO2 emissions) – will emit hundreds of millions of tons over their lifetime. This will add to already-unacceptable levels of CO2 emissions. The United States' greenhouse gas emissions are 12% higher than at the time of adoption of the United Nations Framework Convention on Climate Change and are expected to increase by another 30% in the next 20 years. These new plants would come at a time when the Bush Administration acknowledges the need for drastic reductions in CO2 in order to stabilize greenhouse gases at a level that might avoid the worst environmental consequences of climate change. In the wake of the rejection of the Kyoto Protocol and the absence of any comprehensive program to limit greenhouse gases, it is necessary to look to all available mechanisms to make progress on climate change.

I. "Prevention of Significant Deterioration" and "New Source Review" Permitting Requirements of the CAA

A. The Requirement for Reasoned Decisionmaking

This section introduces two key tenets of administrative law that underlie the Article's entire analysis. First, the "arbitrary and capricious" standard of judicial review requires agencies to make reasonable decisions. Second, what is reasonable, and the amount of discretion afforded to an agency, depends on the circumstances presented. These principles were recently reaffirmed by the Supreme Court in *Alaska Department of Environmental Conservation v. EPA*, which struck down a state BACT decision as unreasonable.

B. The Basic Statutory and Regulatory Framework.

This section outlines the NAAQS/SIP system under the CAA and the role of NSR within it, as well as the basic applicability criteria of NSR.

* NSR matters, despite "NSR Reform" and legislative proposals. Many of the planned new coal-fired power plants are expansions of existing plants or entirely new

* The statute explicitly requires that alternative "production processes," clean fuels," and "innovative fuel combustion techniques" be taken into account in setting BACT.

1. The Choice of Fuels.

This section explains that "Clean fuels" are specified in the BACT definition and must be considered a mandatory element of the decisionmaking process. These include inherently lower-polluting fuels (e.g., gas vs. coal) and cleaner forms of the same fuel (e.g., lower-sulfur coal).

2. The Choice of Production Processes.

This section explains the need to consider alternate production processes under NSR.

* The choice of production process can substantially affect emissions of NAAQS pollutants, toxics, and CO2.
* IGCC is a commercially available production technology for coal-fired plants that has several advantages over older technologies. It has lower emissions rates; greater thermal efficiency, which also reduces emissions; the ability to produce hydrogen for fuel cells; and the ability to separate CO2 emissions for geologic storage when that technology becomes available.

C. Production Efficiency as a Component of BACT and LAER.

This section discusses production efficiency as an element of the NSR control technology analysis.

* Considering production efficiency in determining BACT and LAER can substantially reduce emissions. Emissions limits are typically measured on a fuel or material "input" basis with little regard for total emissions. Measuring limits on an "output" basis – e.g., based on tons of emissions per MWh of electricity produced rather than mmbtu of heat input – reveals that some production processes are more efficient, resulting in lower emissions.
* More efficient processes, with lower total emissions, are more cost-effective than less efficient options. The affordability criterion that is the main driver of BACT and LAER decisions is calculated on a dollars-per-ton-of-pollutant-removed measurement of cost-effectiveness. Measuring emissions on an output basis improves the cost-effectiveness of more efficient technologies.
* More efficient processes cannot serve as a substitute for add-on controls. BACT and LAER must consider the lowest-emitting combination of all pollution reduction methods. Thus, enhanced production efficiency cannot substitute for end-of-stack controls, although its cost can be taken into account.

IV. The Case for Construction of a Truly Clean Coal-Fired Power Plant that Uses IGCC Technology to Minimize Emissions of All Pollutants and Offsets CO2 Emissions

This section outlines the case for weighing an application to construct a coal-fired power plant in light of its CO2 emissions.

A. Why CO2 Emissions Should Be Considered in NNSR and PSD Permitting.

1. The CAA Requires that New Source Review Permit Decisions Take into Account Emissions of "Unregulated" Pollutants Such as CO2 That Have Significant Adverse Environmental Impacts; EPA's Determination That CO2 Is Not an "Air Pollutant" Does Not Affect This Obligation.

This section discusses why EPA's 2003 EPA denial of a petition to regulate CO2 does not alter the case for limiting CO2 via NSR.

* EPA's August 2003 petition response declining to adopt mandatory, comprehensive regulation of CO2 under the CAA has no effect on NSR. The policy, legal, and factual premises of the petition denial are consistent with addressing CO2 through individual NSR permits.

** Policy concerns are not implicated. The petition response was expressly driven by concerns over the huge political and economic consequences of adopting a NAAQS or other comprehensive regulation. In contrast, the Bush Administration has spoken favorably about individual state initiatives on CO2, and using NSR as suggested is fully compatible with that position.

** Legal issues are not implicated. The conclusion in the petition response that CO2 is not an "air pollutant" at all under the CAA simply reasoned backwards from the decision not to regulate and has no implications for NSR. Consideration of CO2 in NSR is not dependent on CO2's status under the CAA but rather on its function as cause of adverse environmental impacts.

** Factual issues are not implicated. The petition response did nothing to question the official U.S. position, as spelled out in *Climate Action Report 2002*, that anthropogenic CO2 emissions cause substantial adverse health and welfare effects

2. Emissions of CO2 Result in Significant, Adverse Environmental Impacts that Merit Careful Consideration in New Source Review Permitting.

This section explains that principles of reasoned decisionmaking should limit agency discretion in considering CO2, since the emissions cause harmful environmental impacts, other regulatory mechanisms are generally lacking, and limiting CO2 through NSR can effectively mitigate those impacts.

a. CO2 Emissions Are Extremely Harmful.

* The United States shares the general consensus that CO2 is a cause of climate change. The United States agrees that manmade emissions of CO2 and other greenhouse damage are a cause of climate change, which in turn will cause extensive environmental harm.

* The fact that climate change is a cumulative problem should not obscure that power plants contribute to the problem. Even power plants – the largest emitters of greenhouse gases – contribute relatively little to climate change on their own. As with other air pollution issues, however, the contribution of large individual emitters to the cumulative problem cannot be excused or overlooked.

b. There Is an Absence of Other Regulatory Mechanisms to Address CO2 Emissions.

* CO2 represents a far greater regulatory gap than any other unregulated pollutant. Environmental impacts of CO2 from power plants should be considered in NSR permitting under the same basic framework that other "unregulated pollutants" have been for over 15 years. Under that framework, CO2 merits far greater consideration than has been needed with respect to other unregulated pollutants because other regulatory mechanisms to address the problem of CO2 generally are lacking.

c. New Source Review Can Effectively Mitigate the Adverse Environmental Impacts of CO2 Emissions.

* NSR mechanisms can limit CO2 emissions and resulting environmental harm. The use of IGCC technology as a result of NSR permitting would limit CO2 emissions through its greater thermal efficiency. Residual CO2 emissions can be further limited by requiring that these emissions be offset through the NSR permit.

B. How CO2 Emissions Should Be Considered in New Source Review Permitting.

This section explains in greater detail how the NSR permitting process should address emissions of CO2.

1. Use of IGCC Technology as a Production Process.

This section outlines the reasons favoring use of IGCC as a production process technology to limit CO2 emissions.

* Even before considering CO2, there are many other factors suggesting that IGCC should be used. Taking thermal efficiency into account by measuring emissions of NAAQS pollutants on an output basis improves IGCC's cost-effectiveness, as does considering its ability to vastly reduce mercury emissions.

* The adverse impacts of CO2 emissions should also be taken into account. Considering the impact of CO2 emissions on climate change militates in favor of using IGCC.

* The likelihood of mandatory CO2 regulation early in the lifespan of a new coal-fired plant suggests that IGCC should be utilized to minimize future regulatory and financial risks. These risks affect how the cost of limiting emissions of regulated NAAQS pollutants from a new plant built today may be affected by future CO2 regulation. A company's failure to mitigate those risks now may saddle states and ratepayers with excess costs in the future.

2. CO2 Offsets as a Permit Condition.

* States are authorized to require CO2 offsets as a way of mitigating environmental harm. Although emissions offsets are only mandated for NAAQS pollutants, states are authorized to requirement more broadly to avoid environmental harm from a new source.

* Building new coal-fired plants only on a "pay as you go" basis by requiring CO2 offsets is appropriate. EPA first required offsets in 1976 when there was no effective air quality planning mechanism to address emissions of NAAQS pollutants from new sources. A similar situation exists today regarding CO2 due to the lack of a comprehensive climate change program.

* Many offset opportunities are available, including market mechanisms. There are numerous available means of satisfying a CO2 offset requirement. Oregon and Washington, for example, have regulatory programs that could be emulated which provide a range of choices, including market mechanisms.

3. Action to Minimize and Offset CO2 Emissions from New Sources Addresses Climate Change and Sustainable Development Obligations under International Law.

* Limiting CO2 emissions through NSR would help to satisfy U.S. obligations under the United Nations Framework Convention on Climate Change (UNFCCC). The Bush Administration has reaffirmed U.S. commitment to the UNFCCC and its goal of stabilizing greenhouse gas emissions at acceptable levels. By minimizing and offsetting CO2 emissions from new plants, the United States would help make progress towards meeting this goal.

* CO2 limits on new sources would help fulfill sustainable development obligations. The Bush administration has reiterated support for the sustainable development principles set out in the 1992 Rio Declaration. It has also acknowledged that "sustainable development must begin at home." CO2 limits on power plants would help fulfill these goals.

V. Available Remedies When Reasoned Decisionmaking Is Lacking in New Source Review

This section is an appendix that summarizes the range of legal remedies available to address deficient NSR permit decisions when states fail to satisfy their obligations for reasoned decisionmaking.

* Both state and federal remedies are available, and intended to insure that permitting authorities make decisions that are reasonable, not "arbitrary and capricious." A range of federal remedies under the Administrative Procedure act and analogs under

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AIR QUALITY

Concerned Citizens of Venice
Friends of Sevier
Utah Chapter Sierra Club
Wasatch Clean Air Coalition
Rocky Mountain Office of Environmental Defense
Western Resource Advocates
Clean Air Task Force

October 17, 2003

Rick Sprott
Utah Department of Environmental Quality
Director, Utah Division of Air Quality
150 North 1950 West
Salt Lake City, Utah 84116

Re: Comments on NEVCO Energy Company's PSD Permit Application for the Sevier Power Company Project (September 2003)

Dear Mr. Sprott:

The Concerned Citizens of Venice, Friends of Sevier, Utah Chapter of the Sierra Club, Wasatch Clean Air Coalition, Rocky Mountain Office of Environmental Defense, Western Resource Advocates and Clean Air Task Force, respectfully provide the following comments on NEVCO Energy Company's September 2003 Prevention of Significant Deterioration Permit Application (Application) for the Sevier Power Company (SPC) Project. We believe it would be contrary to law and harmful to Utah's air quality for the Utah Department of Environmental Quality to determine that the application materials are complete or to provide public notice of the state's intent to approve the proposed construction of this facility without first addressing the serious deficiencies examined in detail below. We greatly appreciate your consideration of our views.

FEDERAL AND STATE CLEAN AIR LAWS REQUIRE NEVCO TO CONSIDER THE APPLICATION OF PRODUCTION PROCESSES AND AVAILABLE

METHODS, SYSTEMS AND TECHNIQUES TO LOWER AIRBORNE CONTAMINANTS.

Integrated Gasification Combined Cycle (IGCC) is an available, demonstrated clean coal combustion technology with significant emission reduction benefits. There are numerous benefits to IGCC, including fewer emissions of criteria and hazardous air pollutants, the opportunity for capturing greenhouse gases, such as CO2, that cause global warming, and a general increase in efficiency over other coal burning technologies. Because NEVCO solely focused on Circulating Fluidized Bed (CFB) coal combustion and did not consider IGCC in the SPC BACT analysis, the Utah Division of Air Quality (UDAQ or Division) must direct the applicant to thoroughly evaluate IGCC as part of the BACT analysis. Indeed, the state has a duty as part of the core of the BACT determination process to provide a reasoned justification for rejecting an available control technology.

Utah and Federal Law Require a Thorough Evaluation of IGCC Cleaner Coal Combustion Technology as Part of the BACT Analysis.

Section 165(a)(4) of the Clean Air Act (CAA) provides that "no major emitting facility on which construction is commenced after August 7, 1977, may be constructed in any area to which this part applies unless…the facility is subject to the best available control technology for each pollutant subject to regulation under this chapter emitted from, or which results from, such facility."[1] The requirement for conducting a BACT analysis is codified at 40 CFR § 51.166(j), in regulations setting forth the requirements for state-administered PSD programs. Utah law, in turn, requires that an approval order may be issued only if "[t]he degree of pollution control for emissions, to include fugitive emissions and fugitive dust, is at least best available control technology. . ."[2]

BACT is then defined under Utah law as follows:

> [A]n emission limitation and/or other controls to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree of reduction of each pollutant subject to regulation under the Clean Air Act and/or Utah Air Conservation Act emitted from or which results from any emitting installation, which the Air Quality Board, on a case-by-case basis taking into account energy, environmental and economic impacts and other costs, determines is achievable for such installation through the application of production processes and available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant.[3]

The wording of the definition of BACT found within Utah's regulations is similar to the federal definition at 40 CFR § 51.166(b)(12). Indeed, Utah's definition of BACT must

[1] 42 U.S.C. §7475(a)(4).
[2] UT Air Quality Rules 307-401-6(1) (hereinafter "UT AQR").
[3] UT AQR 307-101-2.

be consistent with the SIP requirements under federal regulations, which provide that "[a]ll State plans shall use the following definitions for the purposes of this section. Deviations from the following wording will be approved only if the State specifically demonstrates that the submitted definition is more stringent, or at least as stringent, in all respects" as the federal definitions.[4] Thus, the BACT requirement must be implemented and construed under Utah law at least as strictly as EPA and the federal courts have construed it.

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

> Mr. HUDDLESTON. Mr. President, the proposed provisions for application of best available control technology to all new major emission sources, although having the admirable intent of achieving consistently clean air through the required use of best controls, if not properly interpreted may deter the use of some of the most effective pollution controls. The definition in the committee bill of best available control technology indicates a consideration for various control strategies by including the phrase "through application of production processes and available methods systems, and techniques, including fuel cleaning or treatment." And I believe it is likely that the concept of BACT is intended to include such technologies as low Btu gasification and fluidized bed combustion. But, this intention is not explicitly spelled out, and I am concerned that without clarification, the possibility of misinterpretation would remain. It is the purpose of this amendment to leave no doubt that in determining best available control technology, all actions taken by the fuel user are to be taken into account--be they the purchasing or production of fuels which may have been cleaned or up-graded through chemical treatment, gasification, or liquefaction; use of combustion systems such as fluidized bed combustion which specifically reduce emissions and/or the post-combustion treatment of emissions with cleanup equipment like stack scrubbers. The purpose, as I say, is just to be more explicit, to make sure there is no chance of misinterpretation. Mr. President, I believe again that this amendment has been checked by the managers of the bill and that they are inclined to support it.
>
> Mr. MUSKIE. Mr. President, I have also discussed this amendment with the distinguished Senator from Kentucky. I think it has been worked out in a form I can accept. I am happy to do so. I am willing to yield back the remainder of my time.[5]

EPA and federal courts have consistently interpreted the BACT provisions found in the CAA and the agency's regulations as embodying certain core criteria that require the permit applicant either to implement the most effective available means for minimizing

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[4] 40 CFR §51.166(b).

[5] 95th Congress, 1st Session (Part 1 of 2) June 10, 1977 Clean Air Act Amendments of 1977 A&P 123 Cong. Record S9421.

air pollution or justify its selection of less effective means on grounds consistent with the purposes of the Act. In *Citizens for Clean Air v. EPA*,[6] the Ninth Circuit held that "initially the burden rests with the PSD applicant to identify the best available control." As stated in long-standing EPA guidance, "[r]egardless of the specific methodology used for determining BACT, be it 'top-down,' 'bottom-up,' or otherwise, the same core criteria apply to any BACT analysis: the applicant must consider all available alternatives, and [either select the most stringent of them or] demonstrate why the most stringent should not be adopted."[7] Accordingly, the PSD permit applicant not only must identify all available technologies, including the most stringent, but it must also provide adequate justification for dismissing any available technologies.

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

> The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. This includes technologies employed outside of the United States. As discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.[8]

"The term 'available' is used…to refer to whether the technology 'can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term.'"[9] In keeping with the stringent nature of the BACT requirement, EPA has repeatedly emphasized that "available"

> is used in the broadest sense under the first step and refers to control options with a "practical *potential* for application to the emissions unit" under evaluation. . . . The goal of this step is to develop a comprehensive list of control options.[10]

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[6] 959 F.2d 839, 845 (9th Cir. 1992).

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

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

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

[10] In re: Knauf Fiber Glass, PSD Appeal Nos. 98-3 – 98-20 (EAB February 4, 1999), at 12-13 (quoting NSR Manual at B.5) (emphasis added by EAB); see also In re: Steel Dynamics, Inc., PSD Appeal Nos. 99-

EPA adjudicatory decisions also examine the core requirements for the BACT determination process. "Under the top-down methodology, applicants must apply the best available control technology unless they can demonstrate that the technology is technically or economically infeasible. The top-down approach places the burden of proof on the *applicant* to justify why the proposed source is unable to apply the best technology available."[11]

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

Thus, to conduct a BACT analysis consistent with the requirements of state and federal law, NEVCO must thoroughly evaluate all available control measures. IGCC is available today. Utah and federal law therefore require that IGCC be thoroughly evaluated as part of the BACT analysis.

Contrary to law, NEVCO does not consider this available method, system, and technique in its BACT analysis but instead focuses exclusively on CFB. The definitions of BACT under Utah and federal law, and the core requirements of the BACT analysis under federal case law, EPA adjudicatory decisions, and the New Source Review Manual, demonstrate that an available technique such as IGCC must be identified and evaluated as a control option in the first step of the BACT analysis. These are minimum core requirements of a state-administered PSD program.

Recent State Actions Requiring Consideration of IGCC Establish Irrefutable Precedence for the Consideration of IGCC.

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

> Additional material must be provided in the BACT demonstration to address Integrated Gasification Coal Combustion (IGCC) as it is a 'production process'

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4 and 99-5 (EAB June 22, 2000), at 29 n.24 (citing Knauf with approval); NSR Manual at B.10 ("The objective in step 1 is to identify all control options with potential application to the source and pollutant under evaluation."); id. at B.6 (emphasizing that a proper Step 1 list is "comprehensive").

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

> that can be used to produce electricity from coal. In this regard, the Illinois EPA has determined that IGCC qualifies as an alternative emission control technique that must be addressed in the BACT demonstration for the proposed plant. In addition, based on the various demonstration projects that have been completed for IGCC, the Illinois EPA believes that IGCC constitutes a technically feasible production process.
>
> Accordingly, Indeck must provide detailed information addressing the emission performance levels of IGCC, in terms of expected emissions rates and possible emission reductions, and the economic, environmental and/or energy impacts that would accompany application of IGCC to the proposed plant. This information must be accompanied by copies of relevant documents that are the basis of or otherwise substantiate the facts, statements and representations about IGCC provided by Indeck. In this regard, Indeck as the permit applicant is generally under an obligation to undertake a significant effort to provide data and analysis in its application to support the determination of BACT for the proposed plant.[12]

In an ensuing letter, the State of Illinois then formally informed EPA that Illinois has "concluded that it is appropriate for applicants for [proposed coal-fired power plants] to consider IGCC as part of their BACT demonstrations."[13]

Reflecting the viability of IGCC, the State of New Mexico issued a letter on December 23, 2002 requiring the permit applicant (Mustang Energy a subsidiary of Peabody Coal Company) for a proposed new pulverized coal power plant to conduct a site-specific analysis of IGCC as part of the BACT analysis for the proposed facility: "The Department requires a site-specific analysis of IGCC and CFB in order to make a determination regarding BACT for the proposed facility." The New Mexico determination goes on to provide: "The analysis must include a discussion of the technical feasibility and availability of IGCC and CFB for the proposed site in McKinley County, including a discussion of existing IGCC and CFB systems."[14]

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

> Mustang concludes that neither IGCC nor CFB are technically feasible control options for the Mustang site. After careful review of the revised BACT analysis, as well as information gathered from independent sources, the Department

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[12] Letter from Illinois Division of Air Pollution Control to Jim Schneider, Indeck-Elwood, LLC (March 8, 2003), attached hereto.

[13] Letter from Illinois EPA Director to EPA Regional Administrator, Region V (March 19, 2003), attached hereto.

[14] Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Company (Dec. 23, 2002), attached hereto.

determines that Mustang's conclusion is not supported by the evidence. Accordingly, the Department finds that Mustang has not demonstrated the technical infeasibility of IGCC and CFB. Moreover, applying the criteria in the NSR Manual, the Department determines that IGCC and CFB are technically feasible at the Mustang site, and must be evaluated in the remaining steps of the top down BACT methodology.

(a) IGCC and CFB are technically feasible at the Mustang site. A technology is considered to be technically feasible if it is commercially available and applicable to the source under consideration. *See* NSR Manual at B.17-18. A technology is commercially available if it has reached a licensing and commercial sales stage of development. *Id.* A technology is applicable if it has been specified in a permit for the same or a similar source type. *Id.* Mustang's revised BACT analysis indicates that IGCC is commercially available, and IGCC has been specified in air quality permits for coal-fired power plants. *See, e.g.*, Lima Energy Facility, 580 megawatt coal-fired power plant. Similarly, CFB is commercially available and has been specified in air quality permits for coal-fired power plants. *See, e.g.*, AES Puerto Rico 454 megawatt coal-fired power plant; Reliant Energy Seward 584 megawatt coal-fired power plant.

(b) For both IGCC and CFB, Mustang improperly relies on cost to determine technical infeasibility. A technology is technically feasible when the resolution of technical difficulties is a matter of cost. *See* NSR Manual at B.19-20. Mustang's revised BACT analysis indicates that the resolution of technical difficulties for both IGCC and CFB are a matter of cost. These costs do not support a finding of technical infeasibility, but may be considered during Step 4 of the top down BACT methodology. *See* NSR Manual at B.26.[15]

It would be arbitrary and capricious were Utah not to likewise require consideration of IGCC as BACT. The December 2002 and August 2003 New Mexico determinations and the March 2003 Illinois determination are attached hereto.

<u>IGCC Must be Considered in the BACT Analysis.</u>

IGCC is an available method, system and technique for curbing air pollutants from the proposed SPC project consistent with Utah's definition of BACT.[16]

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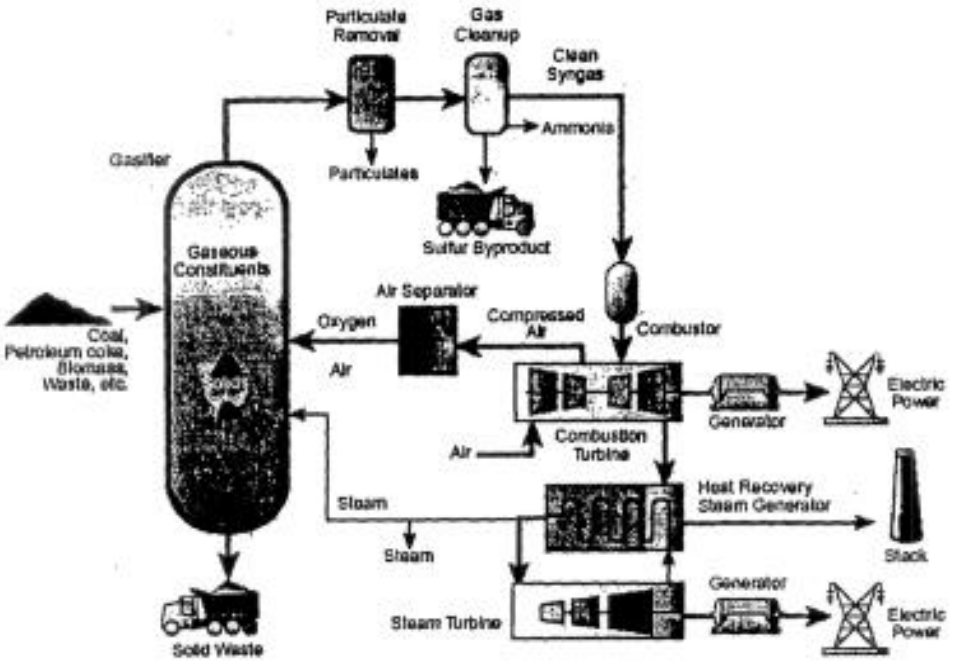
[15] Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Company (Aug. 29, 2003), at p. 3, attached hereto.
[16] UT AQR 307-101-2.

Electricity generation from coal using IGCC technology is a commercially available and proven process. IGCC units generate electricity by integrating a coal gasifier with combined cycle (combustion turbine and steam turbine) electricity generation equipment (see figure below).



Two full scale commercial IGCC electric generating units are in operation in the United States: Tampa Electric Company's 262 MW unit at the Polk plant in Florida and Cinergy's 192 MW unit at the Wabash River plant in Indiana, which both rely on coal as a fuel source.[17] Two other coal-based IGCC plants operate in Europe, NUON/Demkolec is a 253 MW plant in the Netherlands, and ELCOGAS in Spain is 298 MW.[18] IGCC units can be constructed with multiple gasifiers to achieve unit availability at levels comparable to those of conventional baseload facilities. For instance, the Eastman Chemical plant in Kingsport, Tennessee has utilized a dual-gasifier design to produce chemicals from syngas and has experienced 98 percent availability since 1986.[19] ChevronTexaco claims that its new Standard Project Initiative Reference IGCC Plant achieves greater than 90% availability by using multiple gas trains.[20]

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[17] Resource Systems Group, Inc., EPIndex. See www.epindex.com

[18] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Dec 2002, Table 1-7, page 1-26.

[19] Smith, R.G., "Eastman Chemical Plant Kingsport Plant Chemicals from Coal Operations,1983-2000," 2000 Gasification Technologies Conference.

[20] O'Keefe, L. and Sturm, K., "Clean Coal Technology Options – A Comparison of IGCC vs. Pulverized Coal Boilers," presentation to the 2002 Gasification Technologies Conference, October 2002.

Worldwide there are 131 gasification projects in operation with a combined capacity equivalent to 23,750 MW of IGCC units.[21] An additional 31 projects are planned that would increase this capacity by more than 50 percent.[22] Although not all of these projects produce electricity from coal, they demonstrate widespread commercial application of gasification technology for fuel processing, one of two key components of an IGCC plant. The second component is a combined cycle electricity generating system, which is now commonplace for new natural gas fired power plants.

IGCC units are available from major well-known vendors. Coal gasification equipment is available from ChevronTexaco, Shell, and Global Energy, while major turbine manufacturers, including GE and Siemens-Westinghouse, provide combined cycle generators designed to run on the synthesis gas produced by coal gasifiers. Engineers from Texaco, Jacobs Engineering, and GE have teamed up to offer a standardized IGCC design.[23] James Childress, the Executive Director of the Gasification Technology Council, provided testimony to the U.S. Senate Environment and Public Works Committee stating, "[g]asification is a widely used commercially proven technology."[24] At the same hearing, Edward Lowe, Gas Turbine-Combined Cycle Product Line Manager for General Electric Power Systems, stated that, "IGCC is inherently less polluting and more efficient than any other coal power generation technology."[25] Likewise, the National Coal Council, in a May 2001 report, confirms that IGCC is "viable, commercially available technology."[26] ChevronTexaco, in an October 2002 presentation, states that, "IGCC is a current viable choice for clean coal capacity."[27] And the Center for Energy and Economic Development (CEED) states that, "IGCC technology is available for deployment today."[28]

IGCC's Environmental Performance is Superior to CFB for Generating Electricity from Coal.

The coal gasification fuel-processing step in IGCC power plants results in superior environmental performance and lower emissions compared to the CFB technology that is proposed for SPC. Gasifying coal at high pressure prior to combustion facilitates removal

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[21] Simbeck, Dale, SFA Pacific Inc. Gasification Technology Update, presented to the European Gasification Conference, April 8-10, 2002. The total capacity is based on output of synthesis gas. Many of these projects produce chemicals in addition to or instead of electricity.
[22] Id.
[23] O'Keefe, Luke, et al. A Single IGCC Design for Variable CO_2 Capture.
[24] Childress, James M. Statement Submitted for the Record, Senate Environment and Public Works Subcommittee on Clean Air, Wetlands and Climate Change, January 29, 2002.
[25] Lowe, Edward. *Outlook on Integrated Gasification Combined Cycle (IGCC) Technology*. Senate Environment and Public Works Subcommittee on Clean Air, Wetlands and Climate Change, January 29, 2002.
[26] National Coal Council, Increasing Electricity Availability from Coal-Fired Power Plants in the Near Term, p. 20 (May 2001).
[27] "Clean Coal Technology Options – A Comparison of IGCC vs. Pulverized Coal Boilers," Luke O'Keefe and Karl Sturm (ChevronTexaco), October 28, 2002, p. 8.
[28] See www.ceednet.org/fueling/investing.asp

of pollutants that would otherwise be released into the air. According to James Childress, "...criteria pollutant emissions for a coal-based IGCC plant are well below those of even the most modern pulverized coal plants with post combustion cleanup."[29]

IGCC also has several other environmental advantages beyond its reductions in criteria pollutants. Mercury and carbon dioxide (CO_2) removal is easier and less expensive at IGCC units than at other coal-fired plants. Because an IGCC plant is typically 10 to 15 percent more efficient in terms of heat rate compared to a CFB unit,[30] CO_2 emissions -- the primary greenhouse gas responsible for anthropogenic contributions to global warming -- are also reduced by that same amount. In addition, the concentrated CO_2 in the pre-combustion gas stream can be captured and sequestered at a fraction of the cost of post-combustion carbon capture and sequestration other coal plants. The reduced CO_2 emissions rate has important environmental benefits in addressing the urgent problem of global climate change and also reduces increased costs due to future climate change regulations. Even if Utah accepts EPA's recent reversed opinion that CO_2 is not an air pollutant regulated under the Clean Air Act, a position we vigorously disagree with, Utah has a manifest duty under both federal and state law to consider the environmental impacts in determining BACT. The consideration of CO_2 and global warming is most certainly an environmental impact.

Furthermore, mercury removal rates of greater than 90 percent can also be achieved using currently available control technologies with IGCC. DOE states that "an IGCC power plant has the potential of achieving very high mercury removal performance with established technology" and mercury removal in an IGCC power plant can be expected to be very high in removal effectiveness, low in cost, and reliable in design."[31] We examine the mercury pollution control benefits of IGCC in more detail below.

Also, the vitrified solid waste created by IGCC has a number of marketable uses, thereby potentially reducing some of the solid waste disposal issues associated with coal combustion. Indeed, IGCC plants produce 30-50% less solid waste than CFB plants.[32] Again, Utah has a duty under federal and state law to consider the environmental impacts of the solid waste associated with different technology options.

When IGCC permit levels for NOx and PM are compared to SPC's proposed permit levels from the CFB unit, it is clear that IGCC achieves more stringent emission rates.[33]

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[29] Childress, James M. Statement Submitted for the Record, Senate Environment and Public Works Subcommittee on Clean Air, Wetlands and Climate Change, January 29, 2002.
[30] Major Environmental Aspects of Gasification-Based Power Generation Technologies, US DOE, December 2002, Table 1-7, Page 1-26.
[31] "The Cost of Mercury Removal in an IGCC Plant," US DOE, NETL, September 2002 at 1-2.
[32] Major Environmental Aspects of Gasification-Based Power Generation Technologies, US DOE, December 2002, Table 1-7, Page 1-27.
[33] See also "Clean Coal Technology Options – A Comparison of IGCC vs. Pulverized Coal Boilers," Luke O'Keefe and Karl Sturm (ChevronTexaco), October 28, 2002, p. 30-42.

	Permit Levels (lb/MMBtu)			
Pollutant	SPC	Kentucky Pioneer (1)	Lima (1)	Polk Plant (1)
NOx	0.10	.072	.072	0.07
PM	0.015	.011	.011	0.007

(1) Permit limits written in terms of maximum lb/hr. The lb/mmBtu rate estimated from maximum heat input to the plant.

Analyses using consistent economic assumptions show that the cost of a new coal IGCC unit is competitive with the cost of a new well-controlled pulverized coal unit. For example, SFA Pacific, which has conducted studies for EPRI and the World Bank, calculated that a new coal IGCC unit can produce electricity for a total cost of $43 per megawatt-hour (MWh) based on capital costs of $1300/KW and fuel costs of $1/mmBtu. Using the same fuel cost and capital charge rate assumptions, SFA Pacific calculates that an ultra-super-critical pulverized coal plant with flue gas desulfurization (FGD) and selective catalytic reduction (SCR) would have identical electricity generating costs.[34] Were CO_2 removal to be required at both plants, however, the cost of electricity from the IGCC unit would be almost 20% lower than from the pulverized coal plant. If CO_2 removal is not required initially, an IGCC plant can be designed so that it can be easily retrofit for CO_2 removal in the future. The cost of designing this flexibility into an IGCC unit would be minimal—about one percent of the capital cost of the unit according to SFA Pacific.[35]

We have attached hereto a number of materials related to the availability of IGCC.

THE BACT ANALYSIS FAILS TO REFLECT EVEN THE MOST STRINGENT EMISSION LIMITS FOR OTHER CIRCULATING FLUIDIZED BED POWER PLANTS.

While IGCC must be thoroughly evaluated as part of the PSD permit application and as a predicate to a determination by Utah that the permit application is complete, we also note that there are serious deficiencies that must be remedied in evaluating even the proposed BACT emission limits for the CFB boiler. SPC's proposed NOx emission limit of 0.10 lb/mmBtu does not reflect the level of control that can be achieved by the proposed technology and control equipment. Specifically, as stated on page 5-7 of the application, NOx emissions from several other CFB facilities are more stringent than the rate proposed for the SPC project. SPC must achieve a NOx emission rate more stringent

[34] Simbeck, Dale and Donald Wilhelm, *Cost Estimates for Future Coal-Fired Electric Power Generation with and without CO_2 Capture for Sequestration*. Report to NRDC, October 2002.
[35] Id.

into the atmosphere each year. IPP failed to estimate CO_2 emissions, as well as other greenhouse gases entirely. Not only will these emissions affect local people and the immediate environment, it will also add significantly to the global amount of CO_2. Both the Clean Air Act, under NSR provisions, and Utah's administrative rules require that reasonable alternatives be considered. These laws also require that power plants employ the best available control technology.

Greenhouse gas emissions should be considered in each of the ITAs. In fact, the EPA's October 1990 New Source Review Workshop Manual specifically states that "[s]ignificant differences in noise levels, radiant heat, or dissipated static electrical energy, or greenhouse gas emissions may be considered" in assessing environmental impacts from a proposed coal plant. See, EPA NSR Workshop Manual, p. b.49. (attached). According to an article by Gregory B. Foote entitled "Considering Alternatives: The Case for Limiting CO_2 Emissions from New Power Plants Through New Source Review" (attached) Integrated Gasification Combined Cycle (IGCC) is the lowest emitting of all coal production NAAQS pollutant processes. IGCC exhibits superior performance and dramatically lowers the cost of removing mercury and other toxic metals, including CO_2. Foote, at 39. CO_2 removal is more efficient and less expensive at IGCC units. Foote, at 52. Adopting IGCC through NSR will benefit local citizens, help address the serious environmental and economic impacts associated with adding staggering amounts of CO_2 to the atmosphere, and assist the United States in complying with commitments under international law. As previously noted, several states, including some within the Rocky mountain region, treat IGCC as "available" technology under NSR purposes. Although IGCC has numerous benefits, NEVCO and IPSC, as well as UDAQ, did not consider this control technology. IGCC is the most effective control technology available and therefore required under BACT provisions of the Clean Air Act.

Moreover, neither of the ITAs adequately evaluated the use of clean fuels (biomass, etc.) as a means of reducing pollutants, such as greenhouse gases, SO_2, NOx, mercury and other pollutants.

Further, neither ITA evaluated the use of CO_2 offsets as a permit condition. UDAQ should include CO_2 offsets as a permit condition in each ITA to ensure that greenhouse gas emissions are minimized.

Thank you for the opportunity to submit this supplemental comment letter. Please place this supplemental comment letter, including all attachments, in the administrative record for each of the ITAs referenced above.

Sincerely,

Likewise, the National Coal Council, a federal advisory committee to the Secretary of Energy, states: "[I]ntegrated gasification combined cycle (IGCC) has become a viable, commercially available technology. With successes from the Clean Coal Technology Program in both new and repowered projects, much as been learned about IGCC performance, heat rate, cost, and emissions performance. This information, which has been widely published, has become an important tool for evaluation of this technology by electric utilities."[31] ChevronTexaco, in an October 2002 presentation, states that, "IGCC is a current viable choice for clean coal capacity."[32] And the Center for Energy and Economic Development (CEED) states that, "IGCC technology is available for deployment today."[33]

IGCC is an available control technology with demonstrated application.[34] Accordingly, Utah has a statutory duty to consider IGCC in its BACT analysis.

Recent State Actions Requiring Consideration of IGCC Confirm the Statutory Duty to Consider IGCC as a Core Part of Utah's BACT Analysis

Several states have recognized that IGCC is an available technology that must be considered in BACT determinations. In March 2003, the State of Illinois required the applicant for a proposed CFB coal-fired electric generation facility to conduct a robust analysis of IGCC as a core element of its BACT analysis, reasoning as follows:

> Additional material must be provided in the BACT demonstration to address Integrated Gasification Coal Combustion (IGCC) as it is a 'production process' that can be used to produce electricity from coal. In this regard, the Illinois EPA has determined that IGCC qualifies as an alternative emission control technique that must be addressed in the BACT demonstration for the proposed plant. In addition, based on the various demonstration projects that have been completed for IGCC, the Illinois EPA believes that IGCC constitutes a technically feasible production process.
>
> Accordingly, Indeck must provide detailed information addressing the emission performance levels of IGCC, in terms of expected emissions rates and possible emission reductions, and the economic, environmental and/or energy impacts that would accompany application of IGCC to the proposed plant. This information must be accompanied by copies of relevant documents that are the basis of or otherwise substantiate the facts, statements and representations about IGCC provided by Indeck. In this regard, Indeck as the permit applicant is generally under an obligation to undertake a significant effort to provide data and analysis in its application to support the determination of BACT for the proposed plant.[35]

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[31] *Increasing Electricity Availability From Coal-Fired Generation in the Near-Term* (May 2001) (emphasis added).
[32] "Clean Coal Technology Options – A Comparison of IGCC vs. Pulverized Coal Boilers," Luke O'Keefe and Karl Sturm (ChevronTexaco), October 28, 2002, p. 8.
[33] See www.ceednet.org/fueling/investing.asp
[34] See supra notes 8-11.
[35] Letter from Illinois Division of Air Pollution Control to Jim Schneider, Indeck-Elwood, LLC (March 8, 2003), attached hereto.

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In an ensuing letter, the State of Illinois then formally informed EPA that Illinois has "concluded that it is appropriate for applicants for [proposed coal-fired power plants] to consider IGCC as part of their BACT demonstrations."[36]

On December 23, 2002, the State of New Mexico likewise determined that the permit applicant (Mustang Energy a subsidiary of Peabody Coal Company) for a proposed new pulverized coal power plant was required to conduct a site-specific analysis of IGCC as part of the BACT analysis for the proposed facility: "The Department requires a site-specific analysis of IGCC and CFB in order to make a determination regarding BACT for the proposed facility." The New Mexico determination goes on to provide: "The analysis must include a discussion of the technical feasibility and availability of IGCC and CFB for the proposed site in McKinley County, including a discussion of existing IGCC and CFB systems."[37]

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

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

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[36] Letter from Illinois EPA Director to EPA Regional Administrator, Region V (March 19, 2003), attached hereto.
[37] Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Company (Dec. 23, 2002), attached hereto.

(b) For both IGCC and CFB, Mustang improperly relies on cost to determine technical infeasibility. A technology is technically feasible when the resolution of technical difficulties is a matter of cost. *See* NSR Manual at B.19-20. Mustang's revised BACT analysis indicates that the resolution of technical difficulties for both IGCC and CFB are a matter of cost. These costs do not support a finding of technical infeasibility, but may be considered during Step 4 of the top down BACT methodology. *See* NSR Manual at B.26.[38]

And the State of Montana determined, in an administrative appeals proceeding over the PSD permit for the proposed Roundup Power Project, that BACT requires consideration of IGCC: The Department "should have included IGCC and CFB in step 1 [of the BACT analysis] as control technologies." "The applicable definition of BACT includes innovative fuel combustion techniques [i.e., IGCC and CFB]." "The Department should propose the initiation of rulemaking to adopt the top-down five-step method. In the future, the Department should require applicants to consider innovative fuel combustion techniques in their BACT analyses and the Department should evaluate such techniques in its BACT determination in accordance with the top-down five-step method."[39]

These states' consideration of IGCC as part of the BACT determination is consistent with the plain terms of federal and state law. In light of this solid and growing body of precedents from sister states, Utah would be acting unreasonably and thus contrary to law were it not to likewise require consideration of IGCC as BACT.

IGCC Produces Substantial Environmental Benefits and Therefore Must Be Evaluated in Any Meaningful BACT Inquiry into the Maximum Degree of Pollution Reduction

The coal gasification fuel-processing step in IGCC power plants results in substantial air quality benefits. Gasifying coal at high pressure prior to combustion facilitates removal of pollutants that would otherwise be released into the air. According to James Childress, "...criteria pollutant emissions for a coal-based IGCC plant are well below those of even the most modern pulverized coal plants with post combustion cleanup."[40] Our previous submittals to the State of Utah have documented, in detail, the performance benefits in lower criteria pollutants and are hereby incorporated, by reference, into this memorandum.

IGCC also has several other environmental and energy advantages beyond its reductions in criteria pollutants. Because an IGCC plant is typically 10 to 15 percent more efficient in terms of heat rate compared to a circulating fluidized bed (CFB) unit,[41] greater environmental and

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[38] Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Company (Aug. 29, 2003), at p. 3, attached hereto.

[39] Montana administrative appeals proceeding (June 23, 2003) (http://www.deq.state.mt.us/ber/2003_Agendas/june23_03/agendaJune_23_03.asp.)

[40] Childress, James M. Statement Submitted for the Record, Senate Environment and Public Works Subcommittee on Clean Air, Wetlands and Climate Change, January 29, 2002.

[41] Major Environmental Aspects of Gasification-Based Power Generation Technologies, US DOE, December 2002, Table 1-7, Page 1-26.

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Utah Chapter Sierra Club
Wasatch Clean Air Coalition
Grand Canyon Trust
Rocky Mountain Office of Environmental Defense
Western Resource Advocates
Clean Air Task Force

April 9, 2004

By e-mail (jjenks@utah.gov), Fax (801) 536-4099, and Federal Express
John D. Jenks, Engineer
Utah Department of Environmental Quality
Director, Utah Division of Air Quality
150 North 1950 West
Salt Lake City, Utah 84116

Re: Comments on Intent to Approve NEVCO Energy Company's PSD Permit Application for the Sevier Power Company Project (September 2003) DAQE-IN2529001-04

Dear Mr. Jenks:

The Utah Chapter of the Sierra Club, Wasatch Clean Air Coalition, Rocky Mountain Office of Environmental Defense, Western Resource Advocates and Clean Air Task Force, respectfully provide the following comments on Utah Division of Air Quality's ("UDAQ") draft Intent to Approve ("ITA" or "draft permit") NEVCO Energy Company's September 2003 Prevention of Significant Deterioration Permit Application (Application) for the Sevier Power Company (SPC) Project. On October 17, 2003, we submitted extensive comments on NEVCO's revised PSD permit application. For the most part, none of the comments we raised were adequately addressed by UDAQ in the ITA for the SPC Project. A copy of that letter and attachments is attached and incorporated herein by reference to this letter. In summary, we believe it would be contrary to law and harmful to Utah's air quality for the UDAQ to approve the proposed construction of this facility without first addressing the serious deficiencies examined in detail below. We greatly appreciate your consideration of our views and UDAQ's efforts to make documents regarding this action easily available to interested parties.

THE ITA FAILS TO ADDRESS CARBON DIOXIDE AND OTHER GREENHOUSE GAS EMISSIONS

The ITA for the SPC Project did not address carbon dioxide (CO_2) or other greenhouse gases to be emitted from the SPC Project. However, such emissions can be quite significant from coal-fire boilers and, in particular, from circulating fluidized bed (CFB) boilers. The National Coal Council identifies fluidized bed combustion as an especially large source of the greenhouse gas nitrous oxide (N_2O), a problem that is not shared by the most common form of coal combustion technology, pulverized coal (PC):

> "N_2O has a GWP (Global Warming Potential) 296 times that of CO_2. Because of its long lifetime (about 120 years) it can reach the upper atmosphere, depleting the concentration of stratospheric ozone, an important filter of UV radiation. N_2O is emitted from fluidized bed coal combustion; global emissions from FBC units are 0.2 Mt/year, representing approximately 2% of total known sources. N_2O emissions from PC units are much lower. Typical N_2O emissions from FBC units are in the range of 40-70 ppm (at 3% O_2). This is significant because at 60 ppm, the N_2O emission from the FBC is equivalent to 1.8% CO_2, an increase of about 15% in CO_2 emissions for an FBC boiler. Several techniques have been proposed to control N_2O emissions from FBC boilers, but additional research is necessary to develop economically and commercially attractive systems."[1]

NEVCO estimates that the SPC Project has a potential to emit 2.2 million tons of carbon dioxide each year and 1,640 tons of nitrous oxide each year.[2] The nitrous oxide that would be released from the SPC Project is equivalent, in Global Warming Potential, to an additional 485,000 tons per year of carbon dioxide, or an effective 22% increase in the SPC Project's carbon dioxide emissions.

We believe that the EPA, and the State of Utah have a legal obligation to regulate CO_2 and other greenhouse gases as pollutants under the Clean Air Act and the Utah Air Conservation Act. Indeed, twelve states, fourteen environmental groups and two cities have filed suit in federal court stating that EPA must regulate greenhouse gas emissions under the Clean Air Act. Specifically, the parties appealed the U.S. EPA's decision to reject a petition that sought to have the federal government regulate greenhouse gas emissions from new motor vehicles.[3] If the federal court agrees that greenhouse gases, such as CO_2, must be regulated under the Clean Air Act, such a decision would also require the establishment of CO_2 emission limits in this permit for the SPC Project.

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[1] "Coal-Related Greenhouse Gas Management Issues", National Coal Council, May 2003 at page 7.

[2] Letter from Linda Conger of Meteorological Solutions, to John Jenks Utah Division of Air Quality, (December 5, 2003) at Appendix B

[3] Commonwealth of Massachusetts, et al. v. U.S. EPA, No. 03-1361 (Consolidated with Nos. 03-1362-1368) U.S. Court of Appeals for the District of Columbia Circuit.

Similarly, Utah state law also supports regulation of greenhouses gases under the minimum federal requirements and state law. The purposes of the Utah Air Conservation Act is to "provide for a coordinated statewide program for air pollution prevention, abatement, and control." Utah Code Ann. § 19-2-101(4)(a). The term air pollution "means the presence in the ambient air of one or more air contaminants in such quantities and duration and under conditions and circumstances, as is or tends to be injurious to human health or welfare, animal or plant life, or property, or would unreasonable interfere with the enjoyment of life or use of property as determined by the standards, rules, and regulations adopted by the Air Quality Board (Section 19-2-104)." Utah Admin. Rule R307-101-2; Utah Code Ann. § 19-2-102. The State of Utah Division of Air Quality has recognized that "the consensus of most scientists worldwide is that increasing concentrations of greenhouse gases will lead to significant climate warming, shifts in precipitation patterns, and rising sea levels, although the magnitude, timing, and regional patterns of these changes cannot be accurately predicted at this time." Utah Division of Air Quality, *Greenhouse Gas Inventory-1990 and 1993,* available at www.airquality.utah.gov/PLANNING/Grnhsgas.htm. Accordingly, existing state legal authority supports the regulation of greenhouses gases by UDAQ in this permit.

FEDERAL AND STATE CLEAN AIR LAWS REQUIRE NEVCO TO CONSIDER THE APPLICATION OF PRODUCTION PROCESSES AND AVAILABLE METHODS, SYSTEMS AND TECHNIQUES TO LOWER AIRBORNE CONTAMINANTS.

Integrated Gasification Combined Cycle (IGCC) is an available, demonstrated clean coal combustion technology with significant emission reduction benefits. There are numerous benefits to IGCC, including fewer emissions of criteria and hazardous air pollutants, the opportunity for capturing greenhouse gases, such as CO_2, that cause global warming, and a general increase in efficiency over other coal burning technologies. Because NEVCO solely focused on Circulating Fluidized Bed (CFB) coal combustion and did not adequately consider IGCC in the SPC Project's BACT analysis, UDAQ must deny the proposed permit.

Utah and Federal Law Require a Thorough Evaluation of IGCC Cleaner Coal Combustion Technology as Part of the BACT Analysis.

Section 165(a)(4) of the Clean Air Act (CAA) provides that "no major emitting facility on which construction is commenced after August 7, 1977, may be constructed in any area to which this part applies unless…the facility is subject to the best available control technology for each pollutant subject to regulation under this chapter emitted from, or which results from, such facility."[4] The requirement for conducting a BACT analysis is codified at 40 CFR § 51.166(j), in regulations setting forth the requirements for state-administered PSD programs. Utah law, in turn, requires that an approval order may be

[4] 42 U.S.C. §7475(a)(4).

issued only if "[t]he degree of pollution control for emissions, to include fugitive emissions and fugitive dust, is at least best available control technology. . ."[5]

BACT is then defined under Utah law as follows:

> [A]n emission limitation and/or other controls to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree of reduction of each pollutant subject to regulation under the Clean Air Act and/or Utah Air Conservation Act emitted from or which results from any emitting installation, which the Air Quality Board, on a case-by-case basis taking into account energy, environmental and economic impacts and other costs, determines is achievable for such installation through the application of production processes and available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant.[6]

The wording of the definition of BACT found within Utah's regulations is similar to the federal definition at 40 CFR § 51.166(b)(12). Indeed, Utah's definition of BACT must be consistent with the SIP requirements under federal regulations, which provide that "[a]ll State plans shall use the following definitions for the purposes of this section. Deviations from the following wording will be approved only if the State specifically demonstrates that the submitted definition is more stringent, or at least as stringent, in all respects" as the federal definitions.[7] Thus, the BACT requirement must be implemented and construed under Utah law at least as strictly as EPA and the federal courts have construed it.

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

> Mr. HUDDLESTON. Mr. President, the proposed provisions for application of best available control technology to all new major emission sources, although having the admirable intent of achieving consistently clean air through the required use of best controls, if not properly interpreted may deter the use of some of the most effective pollution controls. The definition in the committee bill of best available control technology indicates a consideration for various control strategies by including the phrase "through application of production processes and available methods systems, and techniques, including fuel cleaning or treatment." And I believe it is likely that the concept of BACT is intended to include such technologies as low Btu gasification and fluidized bed combustion. But, this intention is not explicitly spelled out, and I am concerned that without clarification, the possibility of misinterpretation would

[5] UT Air Quality Rules 307-401-6(1) (hereinafter "UT AQR").
[6] UT AQR 307-101-2.
[7] 40 CFR §51.166(b).

remain. It is the purpose of this amendment to leave no doubt that in determining best available control technology, all actions taken by the fuel user are to be taken into account--be they the purchasing or production of fuels which may have been cleaned or up-graded through chemical treatment, gasification, or liquefaction; use of combustion systems such as fluidized bed combustion which specifically reduce emissions and/or the post-combustion treatment of emissions with cleanup equipment like stack scrubbers. The purpose, as I say, is just to be more explicit, to make sure there is no chance of misinterpretation. Mr. President, I believe again that this amendment has been checked by the managers of the bill and that they are inclined to support it.

Mr. MUSKIE. Mr. President, I have also discussed this amendment with the distinguished Senator from Kentucky. I think it has been worked out in a form I can accept. I am happy to do so. I am willing to yield back the remainder of my time.[8]

EPA and federal courts have consistently interpreted the BACT provisions found in the CAA and the agency's regulations as embodying certain core criteria that require the permit applicant either to implement the most effective available means for minimizing air pollution or justify its selection of less effective means on grounds consistent with the purposes of the Act. In *Citizens for Clean Air v. EPA*,[9] the Ninth Circuit held that "initially the burden rests with the PSD applicant to identify the best available control." As stated in long-standing EPA guidance, "[r]egardless of the specific methodology used for determining BACT, be it 'top-down,' 'bottom-up,' or otherwise, the same core criteria apply to any BACT analysis: the applicant must consider all available alternatives, and [either select the most stringent of them or] demonstrate why the most stringent should not be adopted."[10] Accordingly, the PSD permit applicant not only must identify all available technologies, including the most stringent, but it must also provide adequate justification for dismissing any available technologies.

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

> The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of production process or available

[8] 95th Congress, 1st Session (Part 1 of 2) June 10, 1977 Clean Air Act Amendments of 1977 A&P 123 Cong. Record S9421.
[9] 959 F.2d 839, 845 (9th Cir. 1992).
[10] Memorandum from John Calcagni, Director of EPA Air Quality Management Division, to EPA Regional Air Directors (June 13, 1989), at 4 (emphasis added).

> methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. This includes technologies employed outside of the United States. As discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.[11]

"The term 'available' is used…to refer to whether the technology 'can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term.'"[12] In keeping with the stringent nature of the BACT requirement, EPA has repeatedly emphasized that "available"

> is used in the broadest sense under the first step and refers to control options with a "practical *potential* for application to the emissions unit" under evaluation. . . . The goal of this step is to develop a comprehensive list of control options.[13]

EPA adjudicatory decisions also examine the core requirements for the BACT determination process. "Under the top-down methodology, applicants must apply the best available control technology unless they can demonstrate that the technology is technically or economically infeasible. The top-down approach places the burden of proof on the *applicant* to justify why the proposed source is unable to apply the best technology available."[14]

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

Thus, to conduct a BACT analysis consistent with the requirements of state and federal law, UDAQ and NEVCO must thoroughly evaluate all available control measures. IGCC

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

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

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

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

is available today. Utah and federal law therefore require that IGCC be thoroughly evaluated as part of the BACT analysis.

Contrary to law, NEVCO does not adequately consider this available method, system, and technique in its BACT analysis but instead focuses exclusively on CFB. The definitions of BACT under Utah and federal law, and the core requirements of the BACT analysis under federal case law, EPA adjudicatory decisions, and the New Source Review Manual, demonstrate that an available technique such as IGCC must be identified and evaluated as a control option in the first step of the BACT analysis. These are minimum core requirements of a state-administered PSD program.

Recent State Actions Requiring Consideration of IGCC Establish Irrefutable Precedence for the Consideration of IGCC.

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

> Additional material must be provided in the BACT demonstration to address Integrated Gasification Coal Combustion (IGCC) as it is a 'production process' that can be used to produce electricity from coal. In this regard, the Illinois EPA has determined that IGCC qualifies as an alternative emission control technique that must be addressed in the BACT demonstration for the proposed plant. In addition, based on the various demonstration projects that have been completed for IGCC, the Illinois EPA believes that IGCC constitutes a technically feasible production process.
>
> Accordingly, Indeck must provide detailed information addressing the emission performance levels of IGCC, in terms of expected emissions rates and possible emission reductions, and the economic, environmental and/or energy impacts that would accompany application of IGCC to the proposed plant. This information must be accompanied by copies of relevant documents that are the basis of or otherwise substantiate the facts, statements and representations about IGCC provided by Indeck. In this regard, Indeck as the permit applicant is generally under an obligation to undertake a significant effort to provide data and analysis in its application to support the determination of BACT for the proposed plant.[15]

In an ensuing letter, the State of Illinois then formally informed EPA that Illinois has "concluded that it is appropriate for applicants for [proposed coal-fired power plants] to consider IGCC as part of their BACT demonstrations."[16]

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[15] Letter from Illinois Division of Air Pollution Control to Jim Schneider, Indeck-Elwood, LLC (March 8, 2003), attached hereto.

[16] Letter from Illinois EPA Director to EPA Regional Administrator, Region V (March 19, 2003), attached hereto.

Reflecting the viability of IGCC, the State of New Mexico issued a letter on December 23, 2002 requiring the permit applicant (Mustang Energy a subsidiary of Peabody Coal Company) for a proposed new pulverized coal power plant to conduct a site-specific analysis of IGCC as part of the BACT analysis for the proposed facility: "The Department requires a site-specific analysis of IGCC and CFB in order to make a determination regarding BACT for the proposed facility." The New Mexico determination goes on to provide: "The analysis must include a discussion of the technical feasibility and availability of IGCC and CFB for the proposed site in McKinley County, including a discussion of existing IGCC and CFB systems."[17]

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

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

17 Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Company (Dec. 23, 2002), attached hereto.

> when the resolution of technical difficulties is a matter of cost. *See* NSR Manual at B.19-20. Mustang's revised BACT analysis indicates that the resolution of technical difficulties for both IGCC and CFB are a matter of cost. These costs do not support a finding of technical infeasibility, but may be considered during Step 4 of the top down BACT methodology. *See* NSR Manual at B.26.[18]

It would be arbitrary and capricious were Utah not to likewise require consideration of IGCC as BACT. The December 2002 and August 2003 New Mexico determinations and the March 2003 Illinois determination are attached hereto.

Attached is a memorandum from Vickie Patton of Environmental Defense and Joro Walker of Western Resource Advocates explaining the legal basis for requiring consideration of IGCC in the BACT analysis, which was previously provided to your office.

<u>NEVCO Failed to Adequately Address IGCC in the BACT Analysis and the Permit Must be Denied. A Properly Conducted BACT Analysis Shows IGCC is BACT for the SPC Project.</u>

IGCC is an available method, system and technique for curbing air pollutants from the proposed SPC project consistent with Utah's definition of BACT.[19] The extent of analysis by NEVCO of IGCC is limited to the following:

> "Integrated gasification coal combustion (IGCC) was evaluated as an alternative production process for generating electricity from coal. Integrated gasification coal combustion is a two stage process. In the first stage, coal or other fuel are first gasified to produce a synthetic gaseous fuel. In the second stage, this gaseous fuel is then used to fire combined cycle turbines to generate electricity. For the Sevier Power Company Project, IGCC was not chosen due to the higher costs."[20]

NEVCO's vague statement of "higher costs" is a general measure of affordability, and is expressly prohibited by the NSR Manual:[21]

> "In the economical impacts analysis, primary consideration should be given to quantifying the cost of control and not the economic situation of the individual source. Consequently, applicants generally should not propose elimination of control alternatives on the basis of economic parameters that provide an indication of the affordability of a control alternative relative to the source. BACT

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[18] Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Company (Aug. 29, 2003), at p. 3, attached hereto.
[19] UT AQR 307-101-2.
[20] Letter from Linda Conger of Meteorological Solutions, to John Jenks Utah Division of Air Quality, (December 5, 2003) at page 8.
[21] Draft New Source Review Manual, Page B-31

is required by law. Its costs are integral to the overall cost of doing business and are not to be considered an afterthought."

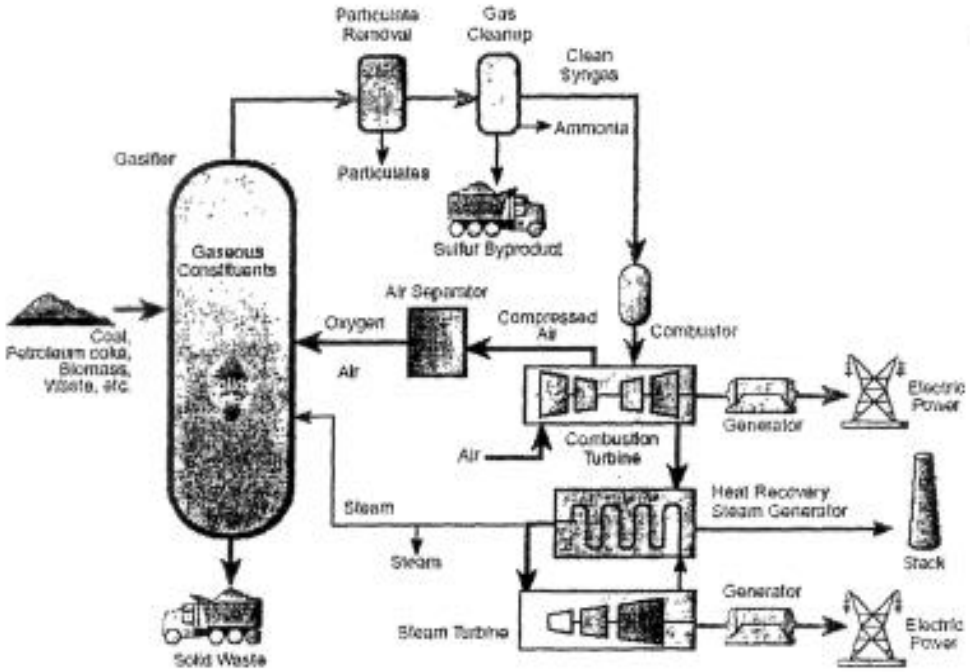
NEVCO should have provided documentation and information consistent with the requirements of a Top-Down BACT analysis. NEVCO's failure to do so requires UDAQ to deny the permit.

The following evaluates IGCC in a Top-Down BACT analysis relative to the CFB and controls selected by NEVCO and proposed in the ITA:

Step 1: Identify All Available Control Technologies.

Conclusion: IGCC is an Available Control Technology

Electricity generation from coal using IGCC technology is a commercially available and proven process. IGCC units generate electricity by integrating a coal gasifier with combined cycle (combustion turbine and steam turbine) electricity generation equipment (see figure below).



Two full scale commercial IGCC electric generating units are in operation in the United States: Tampa Electric Company's 262 MW unit at the Polk plant in Florida and Cinergy's 192 MW unit at the Wabash River plant in Indiana, which both rely on coal as

EXHIBIT 3

Filed
AUG 24 2006
Clerk, Environmental Appeals Board
INITIALS

(Slip Opinion)

NOTICE: This opinion is subject to formal revision before publication in the Environmental Administrative Decisions (E.A.D.). Readers are requested to notify the Environmental Appeals Board, U.S. Environmental Protection Agency, Washington, D.C. 20460, of any typographical or other formal errors, in order that corrections may be made before publication.

BEFORE THE ENVIRONMENTAL APPEALS BOARD
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C.

In re:	
Prairie State Generating Company	PSD Appeal No. 05-05
PSD Permit No. 189808AAB	

[Decided August 24, 2006]

ORDER DENYING REVIEW

Before Environmental Appeals Judges Scott C. Fulton, Edward E. Reich, and Anna L. Wolgast.

requiring it to adopt the process methods that were proprietary to other firms within the fiberglass industry. *See In re Knauf Fiber Glass, GmbH*, 9 E.A.D. 1, 8-11 (EAB 2000).

In the present case, we are satisfied that IEPA took a sufficiently hard look at Prairie State's proposed Facility design to determine whether further emissions reductions would be achievable through inherently lower-polluting processes or methods while still achieving Prairie State's purpose or basic design for the Facility. In particular, IEPA specifically required Prairie State to submit a detailed analysis of Integrated Gasification Combined Cycle ("IGCC") as a method for controlling emissions from Prairie State's proposed Facility. *See* Letter from Donald E. Sutton, P.E., Manager Permit Section, IEPA Division of Air Pollution Control, to Dianna Tickner, Prairie State (Mar. 29, 2003).[30] Notably, IGCC is not simply an add-on emissions control technology, but instead would have required a completely redesigned "power block." Briefly, IGCC involves the conversion of coal to a synthetic gas, which is then burned in a combustion turbine. An IGCC power plant requires the sequential combination of cryogenic oxygen production, gasification (conversion of coal to raw syngas), heat recovery, syngas scrubbing and desulfurization, sulfur recovery, and a syngas-fired combined cycle power block. SFA Pacific, Inc., *Evaluation of IGCC to Supplement BACT Analysis of Planned Prairie State Generating Station* at 6 (May 11, 2003). As we explain below in Part II.B.3, IEPA ultimately concluded that IGCC would not be required for control of SO_2 emissions on the grounds that it has not been shown to achieve greater reductions than the technology proposed by Prairie State. Nevertheless, IEPA's demand that Prairie State provide a detailed analysis of IGCC, which IEPA noted has the promise to achieve greater reductions, demonstrates that IEPA's application of the policy against redefining the design of the source through application of BACT did not treat "very few" design

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[30] IEPA explained that "IGCC is a 'production process' that can be used to produce electricity from coal," that "IGCC is a technically feasible production process," and that IEPA "has determined that IGCC qualifies as an alternative emission control technique that must be fully addressed in the BACT demonstration for the proposed plant." Letter from Donald E. Sutton, P.E., Manager Permit Section, IEPA Division of Air Pollution Control, to Dianna Tickner, Prairie State at 1 (Mar. 29, 2003).

changes as consistent with the proposed Facility's basic design – selection of IGCC would have required extensive design changes to Prairie State's proposed Facility.

Thus, we reject Petitioners' allegation that "IEPA's interpretation would allow a permit applicant to avoid all BACT review by including its preferred fuel, add-on controls, and other pollution controls and hide behind the claim that requiring anything different would unlawfully 'redefine' the proposed source." Petition at 32. Likewise, we reject Petitioners' allegation that "basic design" used as a demarcation between what may or may not be modified through application of BACT would result in an excessive reliance on the "applicant's say-so" eliminating all but a "very few" pollution controls as inconsistent with the "basic design." *See* Response to OAR Brief at 3, 7.[31] To the contrary, IEPA's consideration of IGCC demonstrated that IEPA gave due regard to Prairie State's objective in submitting a permit application for the proposed Facility, namely development of an electric power generating plant that would be co-located and co-permitted with a 30-year supply of fuel, and then explored every potential add-on technology and potentially lower-emitting production processes or methods consistent with that basic design to determine the maximum emissions reductions achievable for the Facility.

For the foregoing reasons, we conclude that Petitioners have not shown that IEPA clearly erred when it determined that consideration of low-sulfur coal, because it necessarily involves a fuel source other than the co-located mine, would require Prairie State to redefine the fundamental purpose or basic design of its proposed Facility and that,

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[31] We reject Prairie State's suggestion that "the coal inherently defines the design of the plant." Prairie State Response at 45. OAR appropriately states that use of low-sulfur coal would not require Prairie State to "fundamentally change the power block at the proposed source" and that the sulfur content of the coal is not itself the "basic design element of the facility." OAR Brief at 10. Rather, as stated in the text, the basic design or fundamental purpose, as found by IEPA, is a coal-fired electric power generating station co-located and co-permitted with a coal mine that will provide a 30-year fuel supply under common ownership or control.

EXHIBIT 4

SETTLEMENT AGREEMENT

WHEREAS, Natural Resources Defense Council, Environmental Defense, Montana Environmental Information Center, American Lung Association of Metropolitan Chicago, Ohio Environmental Council, Valley Watch, Inc., and Sierra Club (collectively "Petitioners") have filed petitions for judicial review of a December 13, 2005 document prepared by the Environmental Protection Agency ("EPA" or "Agency") concerning "Best Available Control Technology Requirements for Proposed Coal-Fired Power Plant Projects" ("December 13, 2005 document"). Natural Resources Defense Council v. EPA, No. 06-1059 (consolidated with Nos. 06-1062 and 06-1063) (D.C. Cir.);

WHEREAS, the December 13, 2005 document addresses matters of broad interest to the states, petitioners and other persons in determining "best available control technology" (BACT) and "lowest achievable emission rate" (LAER) in pre-construction review air quality permits issued under the federal Clean Air Act's Prevention of Significant Deterioration of Air Quality and Nonattainment New Source Review programs;

WHEREAS, the December 13, 2005 document is in the form of a letter from the Director of EPA's Office of Air Quality Planning and Standards to the President of E3 Consulting, LLC;

WHEREAS, the December 13, 2005 document was distributed to all EPA regional offices and posted on EPA's website;

WHEREAS, EPA did not promulgate the December 13, 2005 document as a regulation under section 307(d) of the Clean Air Act;

WHEREAS, EPA did not provide public notice or opportunity for public comment on the December 13, 2005 document before it was prepared;

WHEREAS, the BACT or LAER determination on a draft pre-construction review permit is subject to public notice and comment as part of the proposed basis for issuing a pre-construction review permit;

WHEREAS, EPA has informed Petitioners and other interested parties by letter dated September 12, 2006, that the Agency intends to establish a process that will foster a dialog among a balanced array of interested stakeholder groups on the deployment of advanced coal technology and result in policy recommendations to EPA on this topic;

WHEREAS, it is in the interest of the public, the parties and judicial economy to resolve the issues in this case without further litigation;

NOW, THEREFORE, THE PARTIES AGREE AS FOLLOWS:

I. PARTIES

The parties to this Settlement Agreement are the Petitioners and EPA.

II. TERMS OF THE AGREEMENT

1. EPA agrees and stipulates that the December 13, 2005 document is not final agency action and creates no rights, duties, obligations, nor any other legally binding effects on EPA, the states, tribes, any regulated entity or any person.

2 Not later than 10 days from the date this Agreement is executed by the Parties, the Parties will jointly notify the Court that they have provisionally reached this Settlement Agreement, will lodge the Settlement Agreement with the Court, and request that the Court hold briefing in abeyance in the above-captioned consolidated cases pending completion of the process under section 113(g) of the Clean Air Act and implementation of the Settlement Agreement.

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Attorneys for Utah Chapter of the Sierra Club

BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – the Sevier Power Company 270 MW Coal-Fired Power Plant, Sevier County Project Code: N2529-001 DAQE-AN2529001-04	: : : : :	

In Re: Approval Order – PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station, Millard County, Utah Project Code: N0327-010 DAQE-AN0327010-04	: : : : : :	PROTECTIVE MOTION UNDER UTAH R. CIV. P. 56(f)

The Utah Chapter of the Sierra Club (Sierra Club) respectfully submits this protective motion under Utah R. Civ. P. 56(f), to be considered only in the event the Utah Air Quality Board proposes to convert the motions for judgment on the pleadings filed in these two matters by the Executive Secretary of the Utah Air Quality Board, Sevier Power Company, PacifiCorp, and Intermountain Power Service Corporation into motions for summary judgment. Utah R. Civ. P. 56(f) provides that "[s]hould it appear from the affidavits of a party opposing the motion that [she or] he cannot for reasons stated present by affidavit facts essential to justify [her or] his opposition; the court may refuse the

application for judgment, or may order a continuance to permit affidavits to be obtained or depositions to be taken or discovery to be had or may make such other order as is just." The basis for this motion is described in the attached Declaration of David H. Becker in Support of Protective Motion under Rule 56(f).

Dated: March 19, 2007

JORO WALKER
DAVID BECKER
Attorneys for Utah Chapter of the Sierra Club

CERTIFICATE OF SERVICE

I hereby certify that on this 19th day of March 2007, I caused a copy of the foregoing Protective Motion Under Utah R. Civ. P. 56(f) and the Declaration of David H. Becker in Support of Protective Motion under Rule 56(f) to be emailed to the following:

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BEFORE THE UTAH AIR QUALITY BOARD

In Re: Approval Order – the Sevier Power Company 270 MW Coal-Fired Power Plant, Sevier County Project Code: N2529-001 DAQE-AN2529001-04	:	
In Re: Approval Order – PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station, Millard County, Utah Project Code: N0327-010 DAQE-AN0327010-04	:	DECLARATION OF DAVID H. BECKER IN SUPPORT OF PROTECTIVE MOTION UNDER RULE 56(f)

DECLARATION OF DAVID H. BECKER

I, David H. Becker, affirm and state as follows:

1. I am one of the attorneys for petitioner Utah Chapter of the Sierra Club (Sierra Club) in this action.

2. This affidavit presents facts to support Sierra Club's request under Rule 56(f) of the Utah Rules of Civil Procedure for additional time to conduct discovery, only in the event the Utah Air Quality Board proposes to convert the motions for judgment on the pleadings filed in these two matters by the Executive Secretary of the Utah Air Quality Board (Executive

Secretary), Sevier Power Company (SPC), PacifiCorp, and Intermountain Power Service Corporation (IPSC) (collectively, the "Proponents") into motions for summary judgment.

3. The Proponents have filed motions for judgment on the pleadings with respect to three of Sierra Club's claims in its Requests for Agency Action asking the Utah Air Quality Board (Board) to review the Executive Secretary's approval of air quality permits for IPSC's and SPC's proposed coal-fired power plants. These motions are properly considered under Utah Rule of Civil Procedure 12(c) and the standards developed by Utah courts for considering such motions, which are described in Sierra Club's Consolidated Opposition to Motions for Judgment on the Pleadings (Consolidated Opposition).

4. In the event that the Board deems these motions, or any part of these motions, to be for summary judgment, the Sierra Club asks the Board, pursuant to Rule 56(f), for a continuance of the motions until August 3, 2007 (in the SPC matter) and September 5, 2007 (in the IPSC matter) within which to seek discovery and prepare evidence and expert testimony to respond. This request is based on the following:

a. The Proponents have described and presented their motions as "motions for judgment on the pleadings." On motions for judgment on the pleadings, a reviewing tribunal considers only the complaint, answer, and any other pleadings allowed – in these matters, the pleadings are the Sierra Club's Requests for Agency Action and the responses.

b. In support of its motion for judgment on the pleadings, IPSC attached three exhibits introducing material outside the pleadings, principally in support of its arguments regarding the adequacy of its coal chemistry data, which Sierra Club challenged in Statement of Reason # 5 in Sierra Club's Request for Agency Action in the IPSC matter.

c. The Sierra Club cannot present by affidavit facts essential to justify its opposition to Petitioners' motions and will be unable to do so until they have conducted further discovery regarding the allegations in Proponents' factual submissions and motions.

d. Sierra Club has not yet had an opportunity to conduct discovery since the administrative record and time for taking discovery was opened in mid-February, and the parties have been engaged in briefing preliminary dispositive motions. Preliminary witness lists are not due until April 1, 2007 (in the SPC matter) and May 1, 2007 (in the IPSC matter), with expert reports due by June 20, 2007 (in the SPC matter) and July 15, 2007 (in the IPSC matter).

e. The principal claim on which the Proponents have submitted matters outside the pleadings relate to Sierra Club's Statement of Reason # 5 in the IPSC matter. As described more fully in the Consolidated Opposition, Sierra Club claims that IPSC did not provide, and DAQ did not adequately consider, precise coal chemistry data, that DAQ impermissibly eliminated from the final permit a coal percentage blending limit that the agency had included in the draft permit, and that DAQ's decision was arbitrary and capricious and unsupported by substantial evidence.

f. The DAQ initially included a requirement for a 20% percentage blending limit in the draft permit for IPSC Unit 3, but removed such a limit from the final permit, replacing it with a 30% limit. The permit preparer, DAQ Engineer Milka Radulovich, and other DAQ personnel, indicated in various documents predating the draft permit that a coal quality or blending requirement was needed to set and ensure compliance with various pollutant limitations. The draft permit authorized a blend of Western bituminous and up to 20% sub-bituminous coal. In a technical memorandum to DAQ, IPSC's consultant described that only Western bituminous coal would be used in Unit 3. Yet in other documents, IPSC proposed to look at a range of coals

including both bituminous and subbituminous. The Sierra Club has not had an opportunity to seek further discovery regarding the significant discrepancies between the different submissions by the applicant, or into the change of direction by the agency from the draft permit to the final permit. In particular, Sierra Club has not yet had the opportunity to request production of documents from DAQ or IPSC or take the deposition of Milka M. Radulovich, DAQ Engineer, who prepared the draft and final permits, to explore the reasons for the DAQ's change of direction regarding the proper inclusion of a coal quality/blending percentage limit in the IPSC Unit 3 permit.

g. Other matters that are raised in the Motions for Judgment on the Pleadings are not currently the subject of submissions outside the pleadings. However, I reserve the right to supplement this affidavit to address any materials or attachments which any of the Proponents may submit together with the reply briefs due in these matters on March 26, 2007, and Sierra Club requests that the Board continue any motion for summary judgment based on such attachments until the August and September 2007 post-discovery motions period to allow an orderly discovery process and reasonable time for the Sierra Club to respond to such motions.

I declare under penalty of perjury that the foregoing is true and correct.

Dated this 19th day of March, 2007.

David H. Becker