UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

JUN 0 7 2005

4APT-APB

RECEIVED

JUN 09 2005

BUREAU OF AIR REGULATION

Ms. Trina Vielhauer
Florida Department of Environmental Protection
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Ms. Vielhauer:

Thank you for sending to the Region 4 office of the U.S. Environmental Protection Agency (EPA) the draft prevention of significant deterioration (PSD) permit (Permit No. PSD-FL-344) for a modification of the Seminole Electric Cooperative, Inc. (SECI) Payne Creek Generating Station. The modification consists of adding ten simple cycle Pratt & Whitney combustion turbines configured in five sets of two combustion turbines referred to as Twin Pac sets. Each Pratt & Whitney Twin Pac set has a nominal generating capacity of approximately 60 megawatts. Operation of the Twin Pac sets will be restricted to 2,000 hours per year firing natural gas and 500 hours per year firing distillate fuel oil with a maximum sulfur content of 0.05 percent by weight. The proposed increase in emissions resulting from the project triggers PSD review for nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC).

We have the following comments on the draft permit:

Twin Pac Set Terminology

1. In several permit conditions the Florida Department of Environmental Protection (FDEP) specifies a requirement for a Twin Pac or a Twin Pac set rather than for the individual combustion turbines that comprise a set. For example, Condition III.17.(b) specifies that NO_x emissions "from each Twin Pac shall not exceed a 64 lb/hr average over any calendar month while firing natural gas." This could be taken to mean that one combustion turbine could exceed 64 lb/hr so long as the other had a lower emission rate to yield a set average of 64 lb/hr. If this is what FDEP intended, then it should be so stated to eliminate any confusion.

   As another example, Condition III.7. provides that "Each Twin Pac shall operate no more than 2000 hours on natural gas." It is not clear if this means that each combustion turbine in a given Twin Pac shall operate no more than 2000 hours per year on natural gas or if the sum of the operating hours for both combustion turbines combined shall not exceed 2000 hours per year on natural gas.

Excess Emissions

7. Condition III.19. describes the excess emissions prohibited by the PSD permit. The last sentence of this condition refers to the inclusion of excess emissions in the calculation of the 12-month rolling average for NO_x emissions. Including this sentence in Condition III.19. is not appropriate since the condition is referring to emissions that should not be occurring in the first place, i.e., prohibited emissions. It is more appropriate for this sentence to appear in Condition III.20. Furthermore, the concept of including startup/shutdown emissions should not be limited to NO_x only, but is applicable to any pollutant with an annual emission limit. Therefore, assessment of compliance with the annual limit for CO should include startup/shutdown emissions.

8. Condition III.20. describes the allowed excess emissions that can be excluded from "continuous compliance demonstrations as a result of startup, shutdown, and documented malfunctions." It is our understanding that the draft PSD permit only mandates one continuous compliance demonstration method, the monitoring of the water-to-fuel ratio in lieu of a CEMS for NO_x emissions, and therefore the exclusion would only apply to NO_x emissions. However, excluding startup/shutdown emissions is generally relevant only when a permit includes short-term emissions limits which is not the case for NO_x in this permit. Condition III.17.(b) contains a calendar month NO_x emission limit of 64 lb/hr when firing natural gas. This emission limit is 25.5 percent higher than the equivalent 12-month rolling average of 51 lb/hr that was derived from the annual NO_x emissions used in the applicant's BACT analysis. This monthly emissions limit provides adequate leeway to accommodate temporary fluctuations in combustion turbine NO_x emissions during startup/shutdown. Therefore, EPA's position is that exempting startup/shutdown emissions from compliance with any NO_x emissions limit in this permit is not appropriate.

9. The draft permit does not include definitions of startup and shutdown. The final permit should include definitions.

If you have any questions concerning this letter, please call Jim Little at 404-562-9118 or Katy Forney at 404-562-9130.

Sincerely,

Gregg M. Worley

Gregg M. Worley
Chief
Air Permits Section

Hopping Green & Sams

Attorneys and Counselors

March 23, 2005

Via Hand Delivery

W. Douglas Beason
Assistant General Counsel
Department of Environmental Protection
3900 Commonwealth Boulevard, MS #35
Tallahassee, FL 32399-3000

Re: Public Records Request
Payne Creek Generating Station Peaker Project
File No. 04906340-003-AC
PSD-FL-344
PA 89-25

Dear Mr. Beason:

This letter is an official request, pursuant to Chapter 119, Florida Statutes, for an opportunity to inspect and examine public records relating to the referenced project. For purposes of this request, the term "public records" is intended to have the same meaning as set forth in Section 119.001, Florida Statutes. In addition, for purposes of this request, "document" means all correspondence, e-mails, letters, notes, phone logs, memorandum or other writings whether on paper or in electronic form. If the Department has no documents responsive to a specific request made below, please state in writing. If the Department decides not to produce any document or portion of a document by claiming an exception to Chapter 119, Florida Statutes, provide a description of each such document (or portion) and the statutory basis for not producing it as requested, pursuant to Section 119.07(2)(a), Florida Statute.

The public records that I am requesting access to include the following:

1. The entire project file.

2. All documents between any representatives of the Department of Environmental Protection (including, but not limited to, Mike Halpin, Trina Vielhauer and Al Linero) and the United States Environmental Protection Agency concerning Seminole's application, the Department's

February 4, 2005 Intent to Issue and preliminary BACT determination, or the Department's March 22, 2005 Intent to Deny.

3. All documents between any representative of the Department (including, but not limited to, Mike Halpin, Trina Vielhauer and Al Linero) and General Electric, Siemens Westinghouse, or other combustion turbine manufacturer since August 2004.

4. All documents containing any information related to or analysis used in the Department's Intent to Deny dated March 22, 2005.

5. All PowerPoint presentations made by any representative of the Department (including, but not limited to, Mike Halpin, Trina Vielhauer and Al Linero) related to combustion turbines since January 2002.

6. A copy of all Notices of Withdrawal of Intent to Issue Air Permit issued by the Department since 1995.

7. A copy of all Notices of Intent to Deny Air Permit issued by the Department since 1995.

Sincerely,

Robert A. Manning

Robert A. Manning
HOPPING GREEN & SAMS, P.A.

cc: Patty Adams, DEP
Mike Opalinski, Seminole

Hopping Green & Sams

Attorneys and Counselors

February 8, 2005

RECEIVED

FEB 08 2005

BUREAU OF AIR REGULATION

Via Hand Delivery

Ms. Patty G. Adams
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road, MS-5505
Tallahassee, FL 32399-2400

Re: Public Records Request
Payne Creek Generating Station Peaker Project
File No. 0490340-003-AC
PSD-FL-344
PA 89-25

Dear Ms. Adams:

At Trina Vielhauer's suggestion (see attachment), please accept this letter as an official request, pursuant to Chapter 119, Florida Statutes, for an opportunity to inspect and examine public records relating to the referenced project. For purposes of this request, the term "public records" is intended to have the same meaning as set forth in Section 119.011, Florida Statutes. The public records that I am requesting access to include the following:

1. The entire project file.

2. All correspondence, including letters, emails, or other manner of written communications, between any representative of the Department of Environmental Protection (DEP) and the Environmental Protection Agency (EPA) concerning the Technical Evaluation and Preliminary BACT Determination for the referenced project.

3. All correspondence, including letters, emails, or other manner of written communications, between any representative of the Department of Environmental Protection (DEP) and the Environmental Protection Agency (EPA) concerning EPA's February 1, 2005 letter to DEP addressing the referenced project.

4. All drafts of EPA's February 1, 2005 letter to DEP addressing the referenced project.

5. All drafts of DEP's Technical Evaluation and Preliminary Determination

6. All correspondence, including letters, emails, or other manner of communication, from a representative of DEP to any agency or persons requesting information relative to DEP's research and deliberations on the Technical Evaluation and Preliminary Determination for the referenced project.

7. All responses to the correspondence identified in paragraph 6, above.

8. All correspondence, including letters, emails, or other manner of communication, between representatives of DEP concerning the reference project.

9. All notes or memoranda of representatives of DEP relating to the referenced project.

Thank you for your attention to this request to review public records.

Very truly yours,

James S. Alves

cc: Michael Cooke, DEP
Trina Vielhauer, DEP
Michael Halpin, DEP
Douglas Beason, DEP
Mike Opalinski, Seminole
Jim Frauen, Seminole
Tom Davis, ECT
Robert Manning, HGS

Jeb Bush
Governor

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

January 20, 2005

RECEIVED
JAN 3 1 2005
HOPPING, GREEN & SAMS

Michael P. Opalinski
Vice President of Technical Services
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
PO Box 272000
Tampa, Florida 33688-2000

RE: Payne Creek Generating Station Peaker Project
File No. 0490340-003-AC; PSD-FL-344; PA 89-25

Dear Mr. Opalinski:

I am in receipt of Seminole Electric Cooperative, Inc.'s ("Seminole") January 11, 2005 response to the Department's second request for additional information ("Seminole's letter") for the above reference project. Seminole's letter is currently under review by my staff. I am also in receipt of the December 6, 2004 letter from Mr. Jim Alves referenced in paragraph 6 of Seminole's letter. In both letters, a request is made to review "all information at [your] disposal that the Department apparently intends to utilize to internally estimate the cost effectiveness of hot SCR".

As of today's date, Seminole's application remains incomplete. As I indicated at the December 21, 2004 meeting, the Department is still in the process of evaluating the application, collecting and evaluating appropriate information and documentation, and determining its agency action. Therefore, the Department cannot, at this time, fulfill these requests *as written*. However, if you are interested in conducting a public records review of this application file as it stands on today's date, you are welcome to do so. Please understand that the Department reserves its right to collect, utilize and rely upon any additional information it identifies and deems relevant prior to its proposed agency action. You may arrange a public records review of these files by contacting Ms. Patty Adams at 850/921-9505.

Sincerely,

Trina L. Vielhauer

Trina L. Vielhauer
Chief
Bureau of Air Regulation

cc: Jim Alves and Robert Manning

Seminole

Vielhauer, Trina

From: Halpin, Mike

Sent: Tuesday, February 15, 2005 3:09 PM

To: Vielhauer, Trina; Pennington, Jim

Cc: Linero, Alvaro

Subject: RE: New Turbine Proposed NSPS

The applicant requested 25 ppm NOx emissions for gas (32 lb/hr) and 42 ppm for oil (51.2 lb/hr) per CT. Since the application states that the Generator nameplate rating is 62 MW, it is reasonable to assume that each of the CT's (which comprise the TwinPac) have a capacity greater than or equal to 30MW. The draft NSPS requires 0.39 lb/MW-hr for gas and 1.2 lb/MW-hr for oil for these size units. This equates to required emission limits of approximately 9.5 ppm firing gas and 30.5 ppm firing oil.

I hate to be overly pessimistic, but if my estimates are even close, then I'm quite confident that this new subpart has no chance as written (the turbine manufacturers will band together to oppose it). It is much more likely that in final form, the revised NSPS would allow for 15 ppm on gas (0.62 lb/MW-hr) and 42 ppm on oil (1.65 lb/MW-hr).

Mike

-----Original Message-----
From: Vielhauer, Trina
Sent: Tuesday, February 15, 2005 2:21 PM
To: Halpin, Mike; Pennington, Jim
Subject: FW: New Turbine Proposed NSPS

Mike and Jim,
Have you taken a look at this to see impacts, if any, on Seminole Payne Creek? We should know this before the Monday meeting.

Thx,
Trina

-----Original Message-----
From: Mulkey, Cindy
Sent: Tuesday, February 15, 2005 11:58 AM
To: Linero, Alvaro; Vielhauer, Trina
Subject: RE: New Turbine Proposed NSPS

To comply with KKKK the Keys needs to meet 1.2 lb/MWH

The rationale for this is that turbine manufacturers guarantee a NOx emission level of 42 ppm.

This limit is also based on a 48 percent efficiency consistent with large oil-fired combined-cycle turbines. (EPA is basing the limit for the small simple cycle turbines on an efficiency of 30%.)

EPA believes this is appropriate because there are "almost no oil-fired simple-cycle turbines in the greater than 30 MW category" and are requesting comments on this issue.

EPA has also concluded that most of the simple-cycle turbines are used as peaking units". EPA is requesting comments on an approach to "allow large oil-fired peaking units to meet the same NOx limit that applies to the small units" (1.9 lb/MWH).

The Keys project misses out on both counts. It is a simple cycle unit greater than 30 MW (large). It could meet the 1.9 lb/MWH limit for the smaller units, however it will not qualify as a peaking unit.

It looks like the Keys comes in at 1.53 lb/MWH at full load. This is assuming the 73.7 lb/hr number supplied by GE for 59° and 100% full load.

Also, at partial loads (at which the Keys plan on running) the efficiency is going to decrease, making the lb/MWH go up.

I believe they would need to come down to 57.6 lb/hr which is about 32.5 ppm at full load by my calculations to meet the new standard. Al can confirm this.

It looks like the Keys will be required to use add-on controls to meet the new limits unless a separate limit with new rationale for large simple cycle baseload units is formulated.

Cindy Mulkey
Engineer
Bureau of Air Regulation
Permitting South
(850) 921-8968
FAX (850)921-9533
SC 291-8968

-----Original Message-----
From: Linero, Alvaro
Sent: Tuesday, February 15, 2005 9:45 AM
To: Vielhauer, Trina
Cc: Mulkey, Cindy; Koerner, Jeff
Subject: RE: New Turbine Proposed NSPS

Attached is a rationale I excerpted from the new KKKK.

Looks to me like Keys would not meet it as proposed because the limit of 42 ppm assumes efficiency of 48%. Their turbine is likely to be about 42% (but I'll have to verify).

EPA is taking comment on this issue because they seem to be presuming that large CTs operate in combined cycle.

They are also taking comment on low load considerations.

Bottom line is that I don't think Keys as proposed will comply with KKKK.

They would have to reduce emissions to the 35 bracket or so. I'll have to fine-tune that estimate too.

Cindy is checking to see how they do on a lb/MWH basis which is how they actually wrote the standard.

Pratt & Whitney turbines might fall under different size designation than Keys.

Thanks.

Al.

Hopping Green & Sams

Attorneys and Counselors

February 8, 2005

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BUREAU OF AIR REGULATION

Via Hand Delivery

Ms. Patty G. Adams
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road, MS-5505
Tallahassee, FL 32399-2400

Re: Public Records Request
Payne Creek Generating Station Peaker Project
File No. 0490340-003-AC
PSD-FL-344
PA 89-25

Dear Ms. Adams:

At Trina Vielhauer's suggestion (see attachment), please accept this letter as an official request, pursuant to Chapter 119, Florida Statutes, for an opportunity to inspect and examine public records relating to the referenced project. For purposes of this request, the term "public records" is intended to have the same meaning as set forth in Section 119.011, Florida Statutes. The public records that I am requesting access to include the following:

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Thank you for your attention to this request to review public records.

Very truly yours,

James S. Alves

cc: Michael Cooke, DEP
Trina Vielhauer, DEP
Michael Halpin, DEP
Douglas Beason, DEP
Mike Opalinski, Seminole
Jim Frauen, Seminole
Tom Davis, ECT
Robert Manning, HGS

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

January 20, 2005

RECEIVED
JAN 31 2005
HOPPING, GREEN, & SAMS

Michael P. Opalinski
Vice President of Technical Services
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
PO Box 272000
Tampa, Florida 33688-2000

RE: Payne Creek Generating Station Peaker Project
File No. 0490340-003-AC; PSD-FL-344; PA 89-25

Dear Mr. Opalinski:

I am in receipt of Seminole Electric Cooperative, Inc.'s ("Seminole") January 11, 2005 response to the Department's second request for additional information ("Seminole's letter") for the above reference project. Seminole's letter is currently under review by my staff. I am also in receipt of the December 6, 2004 letter from Mr. Jim Alves referenced in paragraph 6 of Seminole's letter. In both letters, a request is made to review "all information at [your] disposal that the Department apparently intends to utilize to internally estimate the cost effectiveness of hot SCR".

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Sincerely,

Trina L. Vielhauer

Trina L. Vielhauer
Chief
Bureau of Air Regulation

cc: Jim Alves and Robert Manning

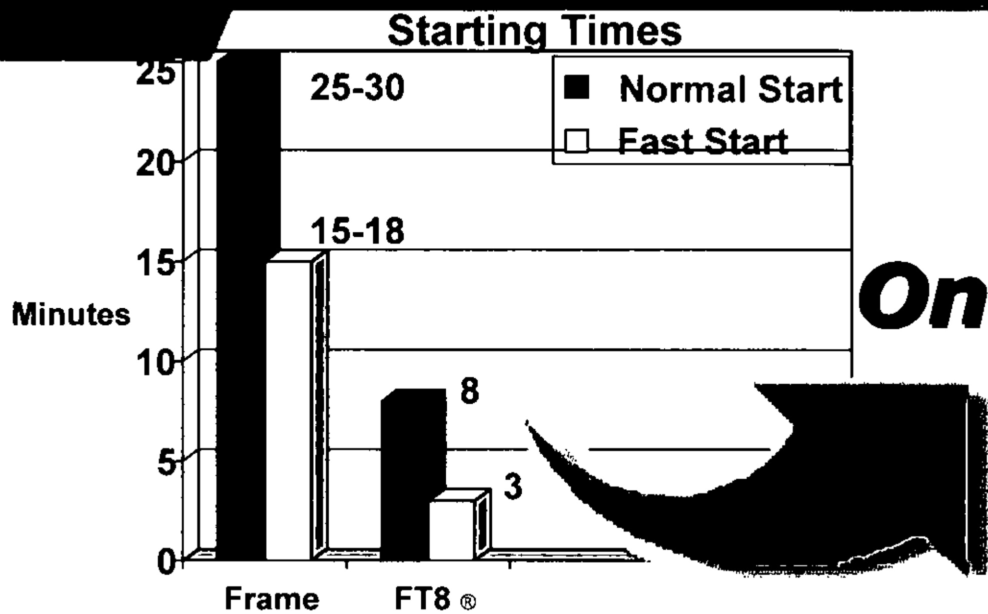
Pratt & Whitney
A United Technologies Company

Seminole Payne Creek

Advantages of FT8
Over
Heavy Duty Frame Gas Turbines

Faster Starting Time

Frame vs. FT8®



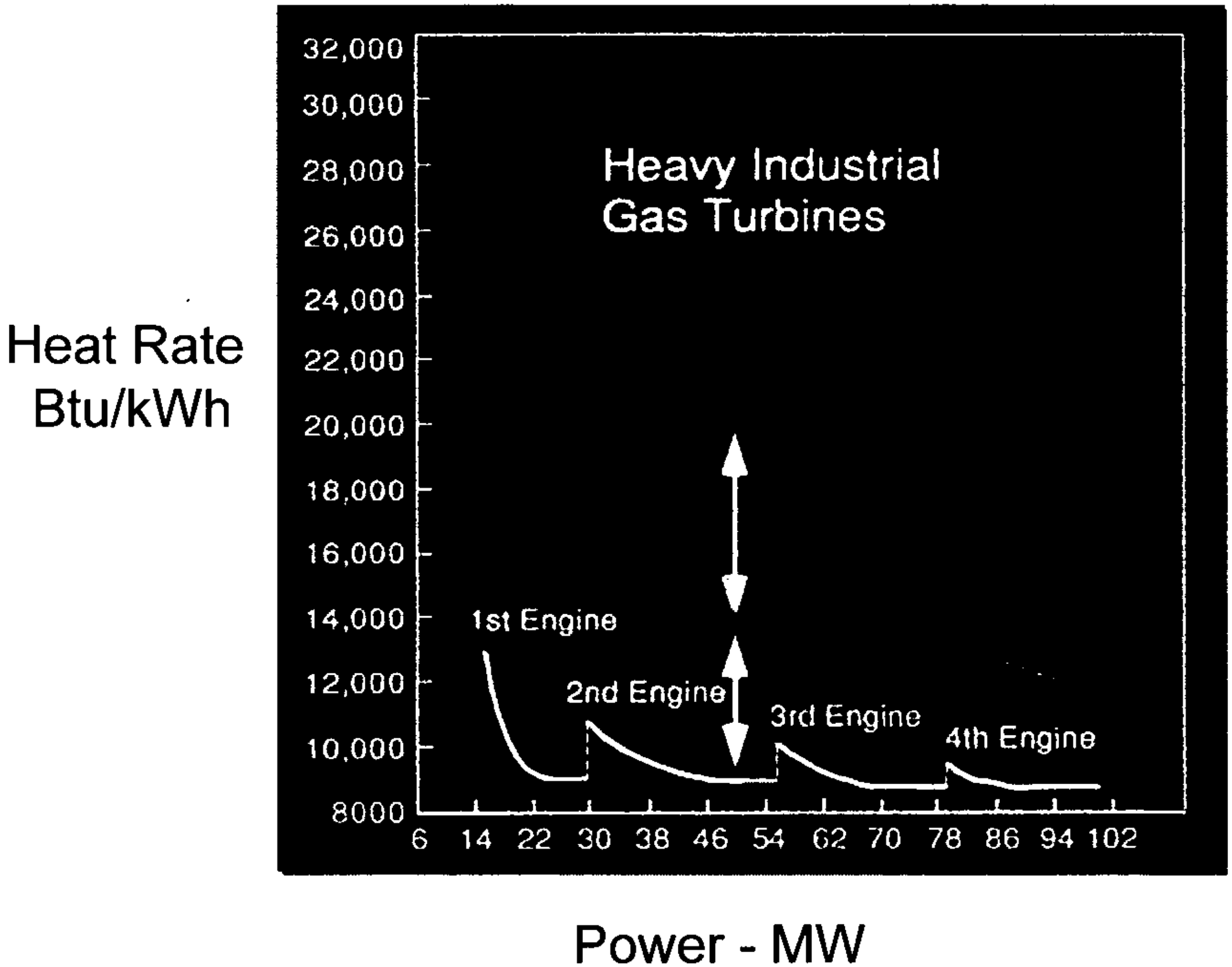
Online Faster Using Less Fuel

More Revenue

Operating Hours Per Start	Increase in Effective Heat Rate
5	4%
3	8%
1	20%

Aero-derivative Advantages

Typical FT8® Fuel Savings…
Two FT8 TWINPAC™'s vs Large Unit



Summary

Advantages
FT8® vs. Frame Machines

Higher Base Load Simple Cycle Efficiency (10 to 15%)

Higher Part Load Simple Cycle Efficiency (20 to 50%)

Faster Starting (3 minutes versus 20 to 30 minutes)

No Operating Hour Penalty for Number of Starts

No Cycle Limitation on Critical Parts Providing Higher Unit Durability

Synchronous Condenser Operation Capability

Faster and Simpler Installation

Higher Unit Availability (3 to 10%) with 8 Hour Complete Unit Change-out

Summary Cont...

Advantages
FT8® vs. Frame Machines

Reliability Based on the World's Most Successful Aero Engine

Easier and Quicker Maintenance (Reduced Outage Completion Time)

- Numerous Borescope Locations for Quick Inspection
- Numerous Field Replaceable /Repairable Parts
- Lease Engine and Major Assembly Program

Longer Time Between Required Overhauls

Future Uprate Capability

Higher Availability/Reliability/Lower Maintenance Cost

Better Start Reliability

Short Order Period

Peak Load Capability

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

FACSIMILE TRANSMITTAL SHEET

To	Mike Halpin - FDEP
Fax Number	(850) 922-6979
From	Jim Little Air Planning Branch, Air Permits Section Phone: (404) 562-9118 Fax: (404) 562-9019 E-mail: little.james@epa.gov
Subject	Consideration of "Alternative Designs" in a BACT Evaluation
Date	January 24, 2005
Pages	15 (including this sheet)

Mike - Here are some materials related to the concept of "alternative designs" in a BACT evaluation. I may look for some other documents as well.

Attachment 1 - An excerpt from a 2002 letter EPA Region 4 wrote to the Kentucky Division for Air Quality on a proposed electric utility steam generating plant with pulverized coal boilers. The main reason for sending this attachment is the statement about the discretion of the permitting agency.

Attachment 2 - An excerpt from the 1990 NSR Workshop Manual on the subject.

Attachment 3 - An excerpt from a 2004 letter from EPA Region 8 concerning a proposed circulating fluidized bed electric utility steam generating plant. The project site is on tribal lands, and EPA is the permit-issuing agency.

Attachment 4 - This is an excerpt from a lengthy legal treatise written by an EPA headquarters attorney (Greg Foote) while he was on a temporary assignment with another organization and not representing EPA. Therefore, the views expressed in this treatise by no means represent any official view by EPA. However, some of the ideas and cited references may be of interest. I can e-mail the entire treatise if you're interested.

3. Alternative Designs and Fuels

We are aware of comments that have been made recommending consideration of alternative designs and alternative fuels. The alternative designs that have been mentioned are circulating fluidized bed boilers and integrated gasification combined cycle combustion turbines. The alternative fuels that have been mentioned include low sulfur coals that are used widely in the eastern United States. As the permitting authority, it is in your discretion to require a detailed evaluation of such alternatives as part of the BACT evaluation. Regardless of whether you elect to require a detailed evaluation before reaching a final BACT determination, we recommend that you include documentation from the applicant in your files providing a rationale as to why a configuration of pulverized coal boilers burning high-sulfur western Kentucky coal was selected for this project and why other design and fuel alternatives were eliminated.

Attachment 1

ATTACHMENT 2

~~technology has the potential to achieve a more stringent emissions level than otherwise would constitute BACT or the same level at a lower cost, it may be proposed as an innovative control technology. Innovative technologies are distinguished from technology transfer BACT candidates in that an innovative technology is still under development and has not been demonstrated in a commercial application on identical or similar emission units. In certain instances, the distinction between innovative and transferable technology may not be straightforward. In these cases, it is recommended that the permit agency consult with EPA prior to proceeding with the issuance of an innovative control technology waiver.~~

~~In the past, only a limited number of innovative control technology waivers for a specific control technology have been approved. As a practical matter, if a waiver has been granted to a similar source for the same technology, granting of additional waivers to similar sources is highly unlikely since the subsequent applicants are no longer "innovative."~~

IV.A.3. CONSIDERATION OF INHERENTLY LOWER POLLUTING PROCESSES/PRACTICES

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 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. Thus, a gas turbine normally would not be included in the list of control alternatives for a coal-fired boiler. However, there may be instances where, in the permit authority's judgment, the consideration of alternative production processes is warranted and appropriate for consideration in the BACT analysis. A production process is defined in terms of its physical and chemical unit operations used to produce the desired product from a specified set of raw materials. In such cases, the permit agency may require the applicant to include the inherently lower-polluting process in the list of BACT candidates.

In some cases, a given production process or emissions unit can be made to be inherently less polluting (e.g; the use of water-based versus solvent based paints in a coating operation or a coal-fired boiler designed to have a low emission factor for NOx). In such cases the ability of design considerations to make the process inherently less polluting must be considered as a control alternative for the source. Inherently lower-polluting processes/practice are usually more environmentally effective because lower amounts of solid wastes and waste water are generated when compared with add-on controls. These factors are considered in the cost, energy and environmental impacts analyses in step 4 to determine the appropriateness of the additional add-on option.

Combinations of inherently lower-polluting processes/practices (or a process made to be inherently less polluting) and add-on controls are likely to yield more effective means of emissions control than either approach alone. Therefore, the option to utilize an inherently lower-polluting process does not, in and of itself, mean that no additional add-on controls need be included in the BACT analysis. These combinations should be identified in step 1 of the top down process for evaluation in subsequent steps.

IV.A.4. EXAMPLE

The process of identifying control technology alternatives (step 1 in the top-down BACT process) is illustrated in the following hypothetical example.

ATTACHMENT 3

EPA RESPONSE TO JUNE 9, 2004 LETTER FROM DESERET POWER

This ~~response incorporates review of Deseret Power's June 9 letter by specialists~~ at EPA's Office of Air Quality Planning & Standards ~~(OAQPS)~~, on the topics of ~~mercury MACT, mercury~~ CEMS, and ~~particulate matter~~ CEMS. A portion of the response on IGCC also incorporates OAQPS review of the June 9 letter.

Integrated Gasification Combined Cycle

At our April 28 meeting with Deseret, we advised Deseret to provide an explanation of why Deseret ruled out Integrated Gasification Combined Cycle (IGCC) technology, as an alternative to a Circulating Fluidized Bed (CFB) boiler. Deseret's June 9 letter responded, in brief, that they investigated and concluded that IGCC is not designed to operate with coal that has a heating value as low as the coal that will be used for their Waste Coal Fired Unit (WCFU). Deseret stated that their waste coal will have an average heating value of approximately 4,000 Btu/lb, with a range from 3,051 to 5,326 Btu/lb. Deseret said that U.S. DOE and NETL representatives they spoke to did not think IGCC would work with coal of such low heating value. Deseret also mentioned high ash content of their own waste coal (about 50%) as another reason to rule out IGCC. Deseret said all IGCC facilities they were aware of utilized coal with ash content of less than 25%.

Our response to Deseret's statements is that we believe Deseret should provide some further discussion of the feasibility or infeasibility of IGCC, specifically in regard to coal blending and pretreating. Our own investigation revealed that waste coal can be used as a feedstock for IGCC, either as a blend or 100% feed if pretreated. Two CFBs in operation by Gilberton Coal use waste coal as their feedstock. We spoke to Gilberton Coal and learned that their waste coal ranges from 2,000 to 7,000 Btu/lb, averaging about 4,000 Btu/lb (about the same as Deseret's proposed WCFU), and has ash content as high as 60% to 70% (more than Deseret's proposed WCFU). It is this same waste coal that Gilberton is going to use in the DOE funded IGCC which is scheduled to be operational in three years. Currently at least two IGCC's are operating in the U.S. that have achieved greater than 90% reliability. Several other IGCC projects are in the design phase, which shows that industry has accepted them as a proven process.

We also wish to respond to the following statement in Deseret's June 9 letter:

"EPA also recognizes that a fluidized bed combustor is the only technology for utilizing coal refuse. 40 CFR Parts 60 and 63 Proposed National Emission Standards for Hazardous Air Pollutants issued January 30, 2004 page 4665 states: "Previously considered unusable by the industry because of the high ash content and relatively low heat content, it (coal refuse) now may be utilized as a supplemental fuel in limited amounts in some units or as the primary fuel in a fluidized bed combustor (FBC). Because of the inherent inability to utilize coal refuse as the primary fuel in anything other than an FBC, it is considered to be a separate coal rank for purposes of the proposed rule."

We have been advised by OAQPS staff who prepared the January 30, 2004 Federal Register notice that EPA did not intend, nor should it be interpreted that, the wording cited in the January 30, 2004, proposed rulemaking infers that FBC units are the only technology for utilizing waste coal. The statement merely says waste coal may be used as the primary fuel in FBC units...not that it can't be used in other units. (The cited language states, in fact, that waste coal may be used in limited amounts in some [other] units.) Nothing is said regarding the use, or not, of waste coal in IGCC units.

Mercury Limit and Mercury CEMS

Clean Air Act section 112(g), and the implementing regulations at 40 CFR 63.43, require Region 8 EPA, as the permitting authority for the WCFU project, to make a case-specific MACT determination. 40 CFR 63.43(d)(4) requires us to consider any relevant EPA-proposed MACT rule when making that determination. On January 30, 2004, EPA Headquarters proposed MACT standards for mercury emissions from coal-fired electric utility units. The proposal includes standards for waste coal fired units and continuous mercury monitoring

As case-specific MACT for mercury, Deseret's PSD permit application does not propose a mercury emission limit, but proposes BACT emission limits for particulate matter and sulfur dioxide as surrogates. In our April 28 meeting with Deseret, we indicated that it was our interpretation of 40 CFR 63.43(d) that an emission limit for mercury itself would be necessary as part of case-specific MACT, in view of the fact that the EPA-proposed MACT rule contains no provision for surrogates to a mercury emission limit. We also indicated that we consider continuous mercury monitoring to be appropriate as required monitoring for case-specific MACT purposes, again in view of the fact that the EPA-proposed MACT rule proposes such monitoring.

Deseret's June 9 letter states that Deseret does not believe any mercury emission limit is appropriate for the WCFU until the EPA-proposed MACT rule is finalized and new regulations set emission limits for similar units. The letter goes on to discuss the proposed MACT rule, to the extent it would pertain to waste coal fired CFBs.

Our response, based on advice from OAQPS staff who wrote the EPA-proposed MACT rule for mercury, is that particulate matter and SO2 are not suitable surrogates for mercury. Rather than avoid establishing a mercury emission limit and continuous mercury monitoring as case-specific MACT until the MACT rule is finalized, the Region and OAQPS believe these requirements should be established in the initial PSD permit, then be relaxed or strengthened in consideration of whatever requirements are finally promulgated.

In its discussion of the proposed mercury MACT rule, Deseret's June 9 letter fails to note that under either of the regulatory options proposed on January 30, 2004, EPA would establish mercury limits for new sources (applicable to all sources commencing construction after January 30, 2004, including the WCFU) AND continuous mercury monitoring (with either CEMS or semi-continuous sorbent traps). Even if the cap-and-trade alternative approach was to be

34 ELR 10642 7-2004

ELR
NEWS & ANALYSIS

ATTACHMENT 4

Considering Alternatives: The Case for Limiting CO_2 Emissions From New Power Plants Through New Source Review

by Gregory B. Foote

Anthropogenic emissions of carbon dioxide (CO_2) and other greenhouse gases are changing the earth's climate in ways that could lead to catastrophe.[1] The United States is the largest emitter of these gases, producing almost one-fourth of worldwide emissions of CO_2, the dominant greenhouse gas.[2] Power plants alone account for one-third of total U.S. emissions of CO_2.[3] A prompt transition to economies based on efficient use of renewable, nonpolluting energy sources rather than carbon-based fuels might avoid the worst effects of climate change by stabilizing greenhouse gases at acceptable levels.[4] But even if that transition begins now, world energy forecasts predict that for the next several decades, fossil fuel use will greatly increase. Of special concern, many new coal-fired power plants may be built in the United States—and elsewhere, particularly in China and other developing countries.[5] In order to limit further harm to the global environment, these plants—if they are built at all—should be constructed in a way that minimizes CO_2 emissions and facilitates future capture and safe storage of those emissions.[6] This Article outlines a way of accomplishing that task under current U.S. law.

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1. *See, e.g.*, Summary for Policymakers: A Report of Working Group I of the Intergovernmental Panel on Climate Change (IPCC) (IPCC Secretariat, Geneva, 2001).
2. *See* U.S. Environmental Protection Agency (EPA), Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001—Final Version 2-1 (2003) (EPA 430-R-03-004), *available at* http://yosemite.epa.gov/OAR/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2003.html.
3. *See id.* tbl. 1-11.
4. *See id.* at 12-14 (CO_2 emissions would need to decline to a small fraction of current levels to stabilize atmospheric levels at 450 parts per million (ppm), a level needed to avoid very substantial adverse environmental consequences, although still involving a significant amount of such effects).
5. Energy Information Administration, International Energy Outlook 2003 (2004), *available at* http://www.eia.doe.gov/oiaf/ieo/world.html; *id.* tbl. A2; "World Total Energy Consumption by Region and Fuel, Reference Case, 1990-2025," *available at* http://www.eia.doe.gov/oiaf/ieo/tbl_a2.html.
6. *See, e.g.*, Patricia Glick, The Toll From Coal: How Emissions From the Nation's Coal-Fired Power Plants Devastate Wildlife and Threaten Human Health (National Wildlife Fed'n 2000), *available at* http://caddodefense.org/download/toll_from_coal.pdf (visited Feb. 20, 2004).

The ultimate goal of the United Nations Framework Convention on Climate Change (UNFCCC) is to stabilize atmospheric concentrations of greenhouse gases at levels that would prevent dangerous human interference with the climate system.[7] The United States ratified the UNFCCC in 1992, and the Bush Administration officially endorsed the scientific consensus on the threat posed by climate change with its submission to the United Nations (U.N.) of *Climate Action Report 2002*.[8] The Administration has also acknowledged that drastic reductions in total greenhouse gas emissions are needed to stabilize atmospheric concentrations,[9] and has funded technological developments toward this end.[10] Many believe that comprehensive programs imposing mandatory CO_2 limits are needed to meet climate change goals. But the United States has declined to ratify the Kyoto Protocol, a first step in market-based, global CO_2 regulation. Instead, the Administration has adopted a program calling for only voluntary reductions in "carbon intensity"—the ratio of CO_2 emissions to economic output—before 2012.[11] Meanwhile, actual U.S. emissions have risen 12% since adoption of the UNFCCC, and are expected to rise another 30% in the next two decades, even assuming very substantial increases in energy efficiency and renewable energy resources.[12] The immensity of the task, and the absence of any program of comprehensive domestic CO_2 regulation, compels consideration of other available mechanisms for making progress on climate change *right now*. This Article proposes one such tool, which requires enactment of no new laws, but merely compliance with provisions of existing law that have been overlooked.

7. For a general description of UNFCCC provisions, obligations, and implementation measures, see United Nations (U.N.) Climate Change Secretariat, A Guide to the Climate Change Convention Process (2002), *available at* http://unfccc.int/resource/process/guideprocess-p.pdf.
8. *See* U.S. Climate Action Report 2002, Third National Communication of the United States of America Under the United Nations Framework Convention on Climate Change [hereinafter Climate Action Report 2002]. Chapter 6 of *Climate Action Report 2002* spells out the adverse impacts on the United States, including temperature and sea level rises, increase in severe weather events, and loss of sensitive ecosystems.
9. *See* U.S. Department of Energy (DOE), Notice of Intent to Prepare a Programmatic Environmental Impact Statement for Implementation of the Carbon Sequestration Program, 69 Fed. Reg. 21514, 21515 (Apr. 21, 2004) ("even modest stabilization scenarios would eventually require a reduction in worldwide greenhouse gas emissions of 50 to 90[%] below current levels").
10. *See id.* (discussing the Administration's Global Climate Change Initiative and Carbon Sequestration Program).
11. *See id.*
12. *See id.*

For the first time in a generation, large numbers of new coal-fired power plants are being planned in the United States.[13] These plants are the largest emitters of greenhouse gases, and under business as usual, each would release hundreds of millions of tons of CO_2 over an expected lifespan of half a century or more. These plants are not entitled to a free pass on greenhouse gases. Instead, they should be seen as a prime opportunity for both limiting CO_2 emissions using currently available production processes and stimulating future technological advancement here and in the developing world. The Clean Air Act's (CAA's) new source review (NSR) permit program can fulfill these purposes.

The NSR program embodies a basic congressional judgment that proposed major new sources of air pollution should assess their environmental impacts—including adverse effects from unregulated pollutants such as CO_2 and mercury—and mitigate those impacts. Considering reasonable alternatives to proposed sources is a key component of this scheme. Due to their huge CO_2 emissions and longevity, new coal-fired power plants merit careful scrutiny because there is no regulatory structure in place to remedy the problem of climate change. In these circumstances, both sound policy and the legal obligation of permitting authorities to make reasonable decisions, call for a "pay-as-you-go" approach that minimizes CO_2 emissions using available technologies and provides offsetting CO_2 reductions elsewhere for emissions that cannot be avoided.

The balance of this Article is divided into five sections:

Section I introduces the general principle of administrative law requiring decisionmaking that is reasonable under the specific regulatory context presented. The section then outlines the relevant statutory and regulatory authorities, purposes, and procedures under NSR provisions of the CAA. It summarizes the requirements for emissions minimization, advocating that available means for reducing emissions should be addressed in a hierarchical fashion. The section then provides an overview of NSR provisions requiring assessment of environmental impacts, including emissions of "unregulated" pollutants such as CO_2 and mercury, and consideration of alternatives to a proposed new source. It highlights the flexible and comprehensive nature of this inquiry.

Section II synthesizes NSR permit cases that address conflicts over the basic parameters of a proposed new source, explaining why there is no basis in law for excluding consideration of alternatives that would "redefine the source" as proposed by a permit applicant. It also addresses the allocation of burdens in considering alternatives to a proposed source, focusing on the insights provided by cases arising in the context of environmental justice. This section also discusses the role of environmental analyses conducted for other purposes in NSR permitting.

Section III outlines generally how alternatives to a proposed new power plant can be appropriately considered, applying the Article's recommended hierarchy of methods for reducing emissions. This section emphasizes the need for permitting authorities to consider all available production processes, and to take into account production efficiency as a means of emissions reduction.

Section IV provides a specific model by which permitting authorities can use NSR to address CO_2 emissions at a new coal-fired plant, by requiring Integrated Gasification Combined Cycle (IGCC) technology to minimize emissions and emissions offsets to mitigate remaining CO_2 emissions. It begins by explaining why the U.S. Environmental Protection Agency's (EPA's) 2003 determination that CO_2 is not an "air pollutant" subject to mandatory CAA regulation has no effect on the need to address CO_2 as an "unregulated" pollutant for NSR purposes. This section also explains how adopting CO_2 measures through NSR would assist the U.S. in complying with commitments under international law to reduce CO_2 emissions pursuant to the UNFCCC, and to follow policies that are consistent with the principles of sustainable development.

Section V is an appendix summarizing the remedies available in the event that permitting authorities fail to make reasoned NSR decisions.

I. Prevention of Significant Deterioration (PSD) and Nonattainment Area NSR Permitting Requirements of the CAA

A. The Requirement for Reasoned Decisionmaking

In explaining the need to consider alternatives in NSR permitting, this Article refers throughout to two key tenets of administrative law. First, with deceptive simplicity, the Administrative Procedure Act (APA) calls upon agencies to make reasonable decisions. Second, what qualifies as reasonable depends on the circumstances of the particular action in question. These principles apply to NSR permit decisions—and most other final agency action—through the "arbitrary and capricious" standard of judicial review under the APA and analogous state laws.[14] The single arbitrary and capricious standard actually encompasses a sliding scale of review. Under that standard the degree of discretion afforded to the decisionmaker and, hence, the degree of scrutiny of the agency decision by a reviewing tribunal, varies depending on the specific regulatory context of the particular matter in question. As a result, the arbitrary and capricious standard serves as a broad umbrella under which a scant analysis may justify a cursory decision in some circumstances, while in other cases a highly developed factual record and detailed analysis is necessary to justify as reasonable a decision that undergoes a hard look by a reviewing body.[15] The need for reasonable decisions is by no means an abstract or academic point; as the U.S. Supreme Court recently affirmed in *Alaska Department of Environmental Conservation v. U.S. Environmental Protection*

13. *See* TRACKING NEW COAL-FIRED POWER PLANTS: COAL'S RESURGENCE IN ELECTRIC POWER GENERATION (National Energy Technology Laboratory 2004), *available at* http://www.netl.doe.gov/coalpower/ccos/pubs/ncp.pdf (last visited Mar. 23, 2004) (listing 94 plants proposed through 2025, with a total anticipated cost of $72 billion; the plants would generate approximately 62,000 megawatts (MW) of electricity); Mark Clayton, *America's New Coal Rush*, CHRISTIAN SCI. MONITOR, Feb. 26, 2004, *available at* http://www.csmonitor.com/2004/0226/p01s04-sten.html.

14. *See* 5 U.S.C. §706; *see also infra* note 226.

15. *See generally, e.g.*, WILLIAM H. RODGERS, ENVIRONMENTAL LAW §3.1 (2d ed. & Fall 2003 Supp.) and cases cited therein.

manner that is sufficiently robust to fulfill the legislative purposes. A comparison of the NNSR alternatives analysis language with corresponding provisions under NEPA and PSD is illustrative.

As noted previously, under NEPA agencies are free to ignore the results of an environmental impact statement (EIS) no matter how meritorious the alternatives presented or how bleak the environmental consequences of the proposed action.[82] Under PSD, where alternatives are placed in consideration by either the applicant/permitting authority or by commenters, the state must provide a reasoned explanation for rejecting the alternatives. It follows that the consideration of reasonable alternatives underlying that explanation should be at least as broad and deep as under NEPA. Consequently, the extensive case law on what constitutes an acceptable weighing of alternatives under NEPA should serve as a baseline in assessing the adequacy of alternatives analysis under PSD.

With respect to NNSR, the state has an explicit burden to justify any decision to build the major new source of air pollution as providing net benefits that "significantly outweigh" the "environmental and social costs" of that decision. Consequently, there is less discretion to reject an environmentally preferable alternative than there would be under PSD, where the state need only justify its decision as reasonable, not as preferable, from the environmental perspective. The NNSR language also means that in many cases the state's decision must be informed by an analysis more detailed than one that would suffice under NEPA. For example, as to mitigation of the adverse environmental impacts that would flow from a decision to build the new source, a merely cursory analysis or summary disposition appears inadequate for NNSR purposes.[83] Moreover, since a separate NNSR provision already requires greater than one-for-one emissions offsets for the pollutants that are the direct subject of the NNSR review, principles of statutory construction dictate that the purposes of the alternatives analysis cannot be satisfied by mere reference to those offsets, since that would render the alternatives analysis superfluous. Rather, it is other environmental impacts that need to be considered—including the impacts of CO_2 and toxic mercury emissions from a new coal-fired power plant.

To recap, the NSR permitting process is open-ended and is intended to raise basic issues about the environmental consequences of a new source of air pollution. The case law and administrative history, however, are almost entirely concerned with "end-of-stack" or "add-on" control technologies. Similarly, most air quality analyses focus on compliance with the NAAQS and increments. Agencies are substantially less experienced with more fundamental questions about the nature, siting, and—at the threshold—the very existence of the prospective new source of pollution. Nevertheless, the law is clear that permitting authorities are required to assess the full range of environmental impacts of a proposed source (including impacts on global climate), consider alternatives to the source as proposed, and justify the permit decision based on these analyses. In this sense, NSR is "NEPA with teeth."

II. "Redefining the Source"

Before examining the particular categories of issues that arise in considering applications to build new power plants, it is useful to synthesize the history of a general, preliminary question: the obligation of permitting authorities to consider alternatives to a prospective new source as presented in a permit application. Despite the clarity of the statutory language requiring consideration of alternatives, some permitting authorities have limited the scope of NSR proceedings to the specific configuration of fuel and production process presented by the applicant. These states appear not to understand their own initial obligation to address statutorily mandated factors, since they treat comments urging consideration of alternatives that would "redefine the source" as nongermane.[84] It is possible that those views are derived from a misreading of case law on PSD permit appeals decisions by the EAB. As discussed below, careful review of this case law reinforces what the statute itself and its legislative purposes already provide, namely that permitting authorities cannot lawfully accept the design or location of a proposed source as a fait accompli. Rather, the proposal is subject to public debate, and permitting authorities must justify on the record of the permit proceeding any decision to reject reasonable alternatives to the proposed source.

A. The EAB Precedents

EPA first addressed the issue of possible limits to the consideration of alternatives in NSR in a 1988 case, *In re Pennsauken County, New Jersey Resource Recovery Facility*,[85] in which a petitioner objected to the construction of a municipal waste combustor that would also produce electricity for sale to the power grid. The petitioner urged that the municipal waste instead be burned in an existing nearby power plant, co-firing the waste with coal. The Administrator ruled that BACT permit conditions "are imposed on the source as the applicant has defined it," and although imposition of BACT conditions "may, among other things, have a

82. *See supra* note 37 and accompanying text.

83. *Cf.* Robertson v. Methow Valley Citizens Council, 490 U.S. 332, 350-52, 19 ELR 20743 (1989) (no need to formulate and adopt a complete mitigation plan under NEPA, since that statute is purely procedural and state agencies—not the federal agency that must comply with NEPA—would be responsible for carrying out any plan to mitigate the adverse effect).

84. *See, e.g.*, Letter from Scott Hassett, Secretary, Wisconsin Department of Natural Resources, to Carl A. Sinderbrand (June 10, 2003) (on file with author). In that correspondence, the state of Wisconsin disclaimed authority to consider IGCC as an alternative to a proposed new pulverized coal boiler, on the ground that these are "different process technologies." *Cf.* CAA §169(3) (BACT requires consideration of available "processes"). The state also asserted that it need not consider IGCC since EPA has not specifically required this in its own guidance, and Wisconsin law prohibits the state from adopting standards more stringent than corresponding federal standards. As to the latter assertion, as discussed in this section, EPA has in fact called upon states to consider alternatives to a proposed source where the failure to do so would constitute an abuse of discretion. Even if Wisconsin were correct that EPA had not spoken (and ignoring that the CAA itself expressly requires consideration of alternative processes), it would not follow that a state law restricting permit terms to those no more stringent than required by EPA would prohibit consideration of IGCC or other alternatives. Rather, the state would be required to follow a BACT process (such as the top-down process Wisconsin adopted consistent with EPA policy) and reach its own conclusions as to what constitutes BACT. In other words, since BACT is essentially a procedural rubric requiring a case-by-case determination, there simply are no "federal standards" that would establish a maximum level of stringency for the state's determination or constrain its consideration of alternatives.

85. *See* 2 E.A.D. 667, 1988 EPA App. LEXIS 27 (Adm'r 1988).

profound effect on the viability of the proposed facility as conceived by the applicant, the conditions themselves are not intended to redefine the source." Thus, the petitioner's objections were "not within the scope of this proceeding."[86]

It seems inappropriate for NSR purposes to consider the goal of the permit applicant—a municipality—to be construction of a waste combustor. A municipality has no proper intrinsic purpose to undertake a particular method of waste disposal. Rather, its governmental function is to dispose of waste in an appropriate way at minimum cost. *Pennsauken* seemed to assume that the municipality's proper purpose was inherently incompatible with the petitioner's suggestion that the task be accomplished by co-firing waste in a preexisting power plant. Yet, at the same time, *Pennsauken* acknowledged that the applicant had no right to construct its desired project, pointing out that the stringency of required end-of-stack controls might threaten the viability of the project altogether.[87] Logically, the ability to deny the permit application subsumes the ability to set conditions short of outright denial, and as noted previously, the CAA legislative history confirms this ability,[88] as does the statutory requirement to consider "alternatives" to a proposed source.[89]

The next year, *In re Hibbing Taconite Co.*[90] involved a permit for modification of a gas-burning boiler to switch to petroleum coke. EPA ruled that the permitting agency had failed to justify its cursory rejection of continued use of gas on economic grounds, since the mere fact of the plant's prior history showed gas to be a viable alternative. The Administrator found that requiring the company to continue burning gas would not "redefine the source" and distinguished *Pennsauken* on the ground that the plant was presently burning gas. This distinction is unpersuasive, however, since the relevant issue in *Pennsauken* was not the economic cost or technical feasibility of the petitioner's suggested alternative of co-firing municipal waste in an existing power plant, but whether the proposal to build a waste combustor in the first place was subject to challenge.

Considering just *Pennsauken* and *Hibbing Taconite*, one might conclude that EPA believes there is a line beyond which alternatives to a proposed source constitute "redefining" the source, and that as such they are beyond the scope of a PSD proceeding. More recent EAB decisions contravene that reading, however, and instead make it clear that even if alternatives brought forward by commenters constitute "redefining" the source, they are within the scope of the PSD proceeding. Newer cases also specify that the permitting authority may ultimately require the alternative to be adopted.[91] The more recent EAB decisions also acknowledge that if the permitting authority rejects a proffered alternative, that rejection constitutes an exercise of discretion that is reviewable to determine whether such discretion was exercised reasonably, and not abused. This formulation was summarized in a 2003 case, *In re Kendall New Century Development*[92]:

> We have previously noted that the Agency's PSD regulations governing permit conditions do not require that a permitting authority consider "redefining the source" as a means of reducing emissions. . . . However, "although it is not EPA's policy to require a source to employ a different design, redefinition of the source is not always prohibited. This is a matter for the permitting authority's discretion." Knauf Fiber Glass, 8 E.A.D. at 136. In order to obtain review of a permit issuer's decision not to conduct a broader BACT analysis that would include redefinition of the source, a petitioner must show a good reason in the circumstances of the case for curtailing the permit issuer's discretion or that the permit issuer abused this discretion.[93]

As *Kendall* reflects, the standard articulated by the EAB in addressing alternatives to the proposed source presumes as an initial matter that the permitting agency must have authority to consider redefining the source in response to criticisms articulated by commenters who propose alternatives.[94] It would be illogical, and contrary to the CAA statutory language and legislative purposes, to conclude otherwise. If states could simply disclaim authority to consider alternatives, by the same thinking they could reject even traditional add-on control devices that exceed some predetermined "disproportionate cost" threshold without providing a case-specific rationale for that decision. The Court has found that to be arbitrary and thus unlawful.[95] For the same basic reason, it also would be improper to accede to any a priori limitations on a permitting authority's responsibility to consider reasonable alternatives to the proposed new or modified source. As the EAB pointed out in *Kendall*, the state cannot abuse its discretion in such matters, and complete failure to consider statutorily mandated factors such as "alternatives" to a proposed source generally or "production processes" in particular plainly constitutes such an abuse.[96]

86. 2 E.A.D. at 667, 1988 EPA App. LEXIS 27, at **13-14.

87. *Id.*

88. *See supra* note 58 and accompanying text.

89. *See supra* Section I.C.3.

90. 2 E.A.D. at 838, 1988 EPA App. LEXIS 24, at **11-12.

91. In re Hillman Power Co., Ltd. Liab. Corp., PSD Appeal Nos. 02-04 et al., ELR ADMIN. MAT. 41255, 2002 EPA App. LEXIS 15, at **46-47 (EAB July 31, 2002) (petitioner asked permitting agency to condition permit so as to prevent applicant's desired requested process modification; agency "clearly has discretion under EPA guidance to consider and even require such a restriction").

92. PSD Appeal No. 03-01, ELR ADMIN. MAT. 41261, 2003 EPA App. LEXIS 3 (EAB Apr. 29, 2003).

93. 2003 EPA App. LEXIS 3, at *30 n.14 (citations omitted).

94. Thus, for example, in In re Hawaiian Commercial & Sugar Co., PSD Appeal No. 92-1, 4 E.A.D. 95, ELR ADMIN. MAT. 40025, 1992 EPA App. LEXIS 42 (EAB July 20, 1992), the EAB addressed a claim that a proposed coal-fired power plant should use gas and a different combustion process. The EAB pointed out that the state permitting agency asserted it lacked authority to exercise its discretion in a way that would impose different fuels, processes, or control devices, *see id.*, 1992 EPA App. LEXIS 42, at **11-14. The EAB then noted that "the definition of BACT includes consideration of both clean fuels and use of air pollution control devices," implying that the state agency's authority to issue PSD permits would be deemed inadequate if the EAB had not ultimately concluded that the petitioner had failed, in any event, to demonstrate that the permit was deficient under the facts of the case. *See id.* Likewise, in *Kendall*, the EAB responded to a similar state assertion that it lacked authority to require that the permit applicant build a smaller number of larger gas turbines than proposed, or require that they be constructed in combined-cycle rather than simple-cycle mode. In a quoted passage the EAB again implied it was necessary that the state agency have authority to exercise the discretion to require such a "redefining" of the proposed source. *See* 2003 EPA App. LEXIS 3, at *30 & n.14.

95. *See* Alaska Dep't of Envtl. Conservation v. EPA, 124 S. Ct. 983, 1007-09, 34 ELR 20012 (2004).

96. *See infra* note 121 and accompanying text. If such a limitation on state authority were allowed, it would have no obvious bright-line boundary, and could lead to a form of gaming whereby the applicant

Regarding the degree of flexibility accorded to permitting agencies in considering proposed alternatives, the EAB's use of the term "abuse of discretion" merits explanation. Nothing in the EAB's precedents suggests an attempt to depart from the governing "arbitrary and capricious" standard for assessing the validity of agency action, of which "abuse of discretion" is a component.[97] Although the EAB, in reviewing administrative decisions based on a record prepared by the permitting agency, has many similarities to a court engaged in judicial review, the EAB is itself an administrative entity. Its authority is delegated by the EPA Administrator, and its decisions constitute final agency action.[98] For the purpose of efficiently ordering its *internal* affairs, EPA has chosen to place great reliance on the initial permitting decisions reached by regional offices and delegated state agencies.[99] This is reflected in the EAB's generally narrow standard for granting EAB review.[100] Thus, absent "clear error," the initial permitting decision is adopted as the core of the Agency action. At that point the entire Agency action, consisting of the initial permit decision as well as the EAB's decision to deny administrative review under its internal, administrative "clear error" standard, is subject to external, judicial review under the APA's usual "arbitrary and capricious" standard.[101] Consequently, a reviewing court would refuse to uphold the rejection of a proffered alternative to the proposed new source if such rejection, considering the administrative record as a whole, constituted an abuse of discretion or otherwise was "arbitrary and capricious."[102]

In examining the issue of what would constitute reasonable, as opposed to arbitrary, state consideration of alternatives, EAB precedents again are illuminating. These decisions provide that the depth of a permitting agency's consideration of alternatives to the proposed source—and the degree of discretion the agency has to accept or reject those alternatives—is a function of the persuasive value of those alternatives. That value in turn is determined by the strength of the factual record presented in support of the proffered alternatives and corresponding legal and policy arguments.[103] Not surprisingly, the EAB's decisions reflect that more obvious and proven alternatives merit greater consideration by the permitting agency than those that are novel and unproven; as to the latter type, there is a correspondingly larger burden on the commenter to marshal facts and arguments in support of its preferred approach.[104] Every aspect of this an-

proposes to construct a source that is defined in a way that makes it not amenable to cost-effective control technology, e.g., choosing a combination of plant site and design configuration that leaves no room for a control device, or proposing to dispose of municipal solid waste by burning it in an open trench. Notably, reviewing courts have rejected such artificial narrowing of the range of alternatives to a proposed project in the analogous NEPA context. *See, e.g.*, Colorado Envtl. Coalition v. Dombeck, 185 F.3d 1162, 1175, 29 ELR 21406 (10th Cir. 1999) (agencies are precluded from "defining the objectives of their actions in terms so unreasonably narrow they can be accomplished by only one alternative (i.e., the applicant's proposed project)"); *see also, e.g.*, Citizens Against Burlington v. Busey, 938 F.2d 190, 196, 21 ELR 21142 (D.C. Cir. 1991) (consideration of alternatives is bounded by a reasonable determination of the objectives of the action in question: "an agency may not define the objectives of its action in terms so unreasonably narrow that only one alternative . . . would accomplish the goals").

97. *See* 5 U.S.C. §706(2)(A). The "discretion" afforded to an agency in addressing alternatives within an informal adjudication does not refer to "agency action [that] is committed to agency discretion by law" within the meaning of the APA because there is no meaningful legal standard against which agency action could be judged or because the decision is inherently discretionary. *See id.* §701(a)(2). Matters committed to agency discretion and presumptively insulated from judicial review are those such as prosecutorial discretion, e.g., Heckler v. Chaney, 470 U.S. 821, 830-31, 15 ELR 20335 (1985) (decision whether to prosecute generally committed to agency discretion and thus immune from judicial review). The discretion at issue in an informal adjudication such as an NSR permit proceeding must be exercised in a "reasoned and justified" manner; failure to do so in determining BACT constitutes "abuse of discretion" under the "arbitrary and capricious" standard of review and renders the permit decision unlawful. *See, e.g.*, Alaska v. EPA, 298 F.3d 814, 823, 32 ELR 20793 (9th Cir. 2002) (lack of reasoned justification for BACT decision constitutes unlawful "abuse of discretion" under arbitrary and capricious standard), *aff'd sub nom. Alaska Dep't of Envtl. Conservation*, 124 S. Ct. at 983.

98. *See* 40 C.F.R. §1.25(e)(2) (EAB performs functions as delegated by the EPA Administrator); *id.* §124.19(a) (EAB jurisdiction over PSD permit appeals).

99. *See, e.g.*, In re Knauf, 1999 EPA App. LEXIS 2, at **14-15 ("[I]n applying this standard for granting review, the [EAB] has been guided by the following language in the preamble to section 124.19: the 'power of review should be only sparingly exercised' and 'most permit conditions should be finally determined at the [permitting authority] level.' 45 Fed. Reg. 33290, 33412 (May 19, 1980)").

100. *See* 40 C.F.R. §124.19(a)(1). Note, however, that in addition to this narrow internal standard, under 40 C.F.R. §124.19(a)(2) the EAB also may grant review where there is an "exercise of discretion or an important policy consideration which the [EAB] should, in its discretion, review").

101. Citizens for Clean Air v. EPA, 959 F.2d 839, 845-46, 22 ELR 20669 (9th Cir. 1992). NSR permitting under federal law is a form of licensing not subject to decision "on the record" after a formal, trial-like hearing. Thus, in APA terminology, it is an "informal adjudication." *See* 5 U.S.C. §§501(4)-(9), 554.

102. *See* 959 F.2d at 845-46; *see also Alaska Dep't of Envtl. Conservation*, 124 S. Ct. at 1006-07 (judicial review of BACT determination under arbitrary and capricious standard); Sur Contra la Contaminacion v. EPA, 202 F.3d 443, 447-48, 30 ELR 20358 (1st Cir. 2000) (*same*).

103. *See, e.g.*, In re Hawaiian Commercial & Sugar Co., PSD Appeal No. 92-1, 4 E.A.D. 95, ELR ADMIN. MAT. 40025, 1992 EPA App. LEXIS 42 (EAB July 20, 1992). The EAB cited the Workshop Manual at B.13 as providing that permitting agencies have discretion in selecting production technology, and found that petitioner "has provided no good reason" to conclude that the agency "abused this discretion" in that case. *Id.* at **11-14. *See also* In re Knauf Fiber Glass, GmbH, 30 ELR 41218, 1999 EPA App. LEXIS 2, at **37-52 (EAB Mar. 14, 2000) (petitioner claimed that agency had failed to consider more efficient production process; permit decision remanded for consideration of that option). Notably, the form of analysis used in these decisions is the usual one in review of alternative courses of action presented in administrative decisions.

104. *See, e.g.*, *Citizens for Clean Air*, 959 F.2d at 846-47 (petitioners seeking to require recycling as condition of construction of municipal incinerator had particularly heavy burden of demonstrating that their preferred alternative constituted BACT because at the time considering the air quality benefits of recycling required the agency to "embark upon an exploration of uncharted territory" (quoting Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council, 435 U.S. 519, 553, 8 ELR 20288 (1978)).

For another example, on the issue of technology transfer from one source category to another, *compare* In re Mecklenburg Cogeneration Ltd. Partnership, 3 E.A.D. 492, 494 n.3, 1990 EPA App. LEXIS 42, at *4 n.3 (Adm'r 1990):

> [A] permit issuer does not commit clear error if it carefully considers the potentially transferable technologies in the context of a particular project . . . but its level of consideration or documentation nonetheless falls short of matching the level that would be expected, for example, if the permit issuer were rejecting a top technology with a proven track record in the same source category. A rule of reason proportionate to the technology's track record necessarily governs how much detail and documentation must go into consideration of a particular technology.

with In re Pennsauken County, N.J. Resource Recovery Facility, 2 E.A.D. 667, 1988 EPA App. LEXIS 27, at *10 (Adm'r 1988) (permit determination remanded where rejected technology was in use domestically in the same type of facility but the BACT determination alytical framework is fully consistent with the mainstream of black-letter administrative law.

B. Environmental Justice and the Allocation of Burdens in Considering Alternatives Under PSD

Despite the EAB's clear acknowledgement of the need to consider alternatives to a proposed new source, the EAB's jurisprudence with respect to alternatives that the EAB characterizes as seeking to "redefine the source" reflects a seeming discomfort with addressing issues that it views as better handled by state agencies. This may be due at least in part to the understandable desire to maintain comity with the states, and a sense that states are better equipped to make basic economic growth decisions.[105] The EAB displays no such reluctance, however, to engage fundamentally similar issues that arise under the rubric of environmental justice. Examination of this perceived anomaly reveals that in actuality the EAB has applied a uniform standard of review to both types of cases. The apparent disparity simply reflects distinctions between the procedural contexts of these classes—specifically, whether the matter at issue is within the class of issues which the permitting authority has a mandatory duty to consider on its own initiative, or whether the commenter has the burden of presenting it for consideration.

Environmental justice claims arising under NSR assert that a new source of pollution will result in disproportionately high and adverse human health or environmental effects on minority or low-income populations, and the party's desired remedy typically is to build the source elsewhere or, in some instances, not at all. As such, it is quite clear that environmental justice claims do seek to "redefine the source" as that term has been used by the EAB. Nevertheless, the EAB has not characterized environmental justice claims in that manner. For example, in *In re EcoElectrica, Ltd. Partnership*,[106] the petitioner raised an environmental justice claim expressing concern with the air quality impacts of locating a proposed power plant in lower income towns in Puerto Rico; the petitioner separately claimed that energy efficiency projects could obviate need for the plant altogether. The EAB was solicitous of the environmental justice claim and, while ultimately rejecting it on the merits, expressed no concern regarding the ability of the EPA permitting office to address the claim.[107] Conversely, the EAB stated that the petitioner's claim that conservation could substitute for the new power plant constituted an attempt to "redefine the source" and was more appropriately addressed to commonwealth officials.[108]

The environmental justice claim in *In re EcoElectrica*, if successful, plainly would have "redefined the source" by resulting in it not being built at all, or being sited in a location different from that proposed by the applicant. The difference in the EAB's characterization of the environmental justice claim and the energy efficiency claim and its treatment of them is readily reconciled, however, by viewing the claims within the normal administrative law framework for review of agency action. The permitting agency was obligated to address environmental justice by the issuance of Executive Order No. 12898, which expressly directed EPA to incorporate environmental justice concerns into Agency decisions.[109] By its terms, that Executive Order is only procedural in nature, and adds no substantive legal obligations.[110] Accordingly, since environmental justice claims (like many other claims that a permitting authority should consider alternatives to a proposed source) seek to "redefine the source," it follows that characterizing any claim as one that would "redefine the source" does not render it ineligible for consideration in the permitting exercise.

Rather, what is significant about environmental justice in illuminating the larger issue of considering alternatives in NSR permitting is that by adopting the policy of "identifying and addressing" potential disparate impacts on minority and low-income communities,[111] the permitting authority—here, EPA—altered the regulatory context. It did so by placing environmental justice within the class of issues arising in NSR permitting that are a *mandatory* component of the preconstruction review. As a result, if the permitting agency failed to adequately address the issue in the permitting exercise, and if a commenter pointed out that failure and its significance, the permit would be found deficient and remanded to correct the deficiency. As noted, in *In re EcoElectrica* the EAB held that the permitting agency had adequately addressed the environmental justice issue in crafting the permit, and so ultimately rejected the claim on its merits.

In contrast, there was no equivalent policy directing EPA to consider the claim in *In re EcoElectrica* for efficiency-based alternatives to the proposed plant. Thus, the mere fact that the permitting agency had not considered those alternatives in preparing the permit did not render the permit legally deficient, because the agency had no mandatory duty to address those alternatives on its own initiative. Rather, under the specific regulatory context, it was the commenter's obligation to raise the issue and present a persuasive case as to why failure to consider its preferred alternatives would be a reasonable exercise of discretion. Consequently, in *In re EcoElectrica* the EAB needed to do no more than note the absence of effective advocacy by petitioner of the energy conservation alternative, and in particular the complete failure to demonstrate how the claim related to the requirements of BACT or other PSD provisions.[112] As a result, the EAB found that the permitting agency acted reasonably under the record of the case in cursorily rejecting the claim.[113]

lacked the "detail and analysis" necessary to show that the rejected technology was technically or economically unachievable by the proposed source).

105. *See infra* note 108 and accompanying text. This concern over the respective roles of EPA and the states would not arise, of course, as to state-issued permits.

106. *See* 7 E.A.D. 56, ELR ADMIN. MAT. 40632, 1997 EPA App. LEXIS 5, at **27-28 and **36-43 (Apr. 8, 1997).

107. *See* 7 E.A.D. at 56, 1997 EPA App. LEXIS 5, at **27-31.

108. *See* 7 E.A.D. at 56, 1997 EPA App. LEXIS 5, at **39-42.

109. *See* 7 E.A.D. at 56, 1997 EPA App. LEXIS 5, at **27-28 (citing Exec. Order No. 12898, 3 C.F.R. §859 (1995), ELR ADMIN. MAT. 45075 (Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations).

110. *See, e.g.*, Sur Contra la Contaminacion v. EPA, 202 F.3d 443, 449, 30 ELR 20358 (1st Cir. 2000) (Executive Order No. 12898 was "intended only to improve the internal management of the executive branch"; by its own words, the order 'shall not be construed to create any right to judicial review'" (quoting Exec. Order No. 12898, *supra* note 109, §6-609)).

111. Exec. Order No. 12898, *supra* note 109, §1-101.

112. 7 E.A.D. at 56, 1997 EPA App. LEXIS 5, at **36-37 & n.23.

113. 7 E.A.D. at 56, 1997 EPA App. LEXIS 5, at **39-41.

This same review format is evident in *In re Knauf*[114] as well. There, the commenters' environmental justice claim had been summarily rejected by the permitting agency. In petitioning EAB, the commenters needed only to point out the agency's essential failure to address a mandatory issue and its potential impact on the outcome of the permit proceeding. The petitioners did so, and the EAB found that the agency's failure to explain its basis for rejection of the environmental justice issue (as contrasted to the detailed explanation provided in *In re EcoElectrica*) rendered the permit deficient. Accordingly, the EAB remanded the matter for further consideration, placing the obligation on *the agency* to document its findings on environmental justice and provide an opportunity for public comment on them.[115]

As had occurred in *In re EcoElectrica*, commenters in *In re Knauf* also raised claims that on appeal the EAB characterized as an attempt to redefine the source. Specifically, they sought to require that the permitting agency consider a fundamentally different production process.[116] In *In re Knauf*, however, the petitioners carried their burden of explaining how the different production technology merited consideration as BACT. Consequently, the Board ordered that the permit be remanded to determine whether the alternative process was "available," and if so, to consider it as a BACT option, because enabling the permit applicant to artificially limit the range of fundamental project designs to its preferred process technology would undermine the statutory purpose.[117]

In sum, *In re EcoElectrica* and *In re Knauf* illustrate that whether a proffered alternative to a proposed new source is characterized as a request to "redefine" it is merely a way of framing an issue as possibly arising toward the discretionary end of the administrative decisionmaking spectrum. Such characterization does not alter in any fundamental way the permitting authority's ultimate responsibility to consider the BACT alternatives presented and explain the basis for its decision. The general obligation for reasoned decisionmaking is uniform, as is the obligation to provide a reasoned justification for rejection of any BACT options that are more stringent than the applicant's preferred approach. What can vary is the allocation of the burden to present alternatives at issue in the first instance and the degree of discretion afforded to the permitting authority in addressing the alternatives once they have been brought forward for consideration. Hence, deeming an alternative as one that would "redefine the source" merely signals that, in the PSD context, such an alternative is usually—but not always—treated as being beyond the range of mandatory permitting issues that the applicant and the permitting authority have the obligation to address in the first instance. Where consideration of the alternative is not mandatory, commenters have the burden of presenting the case that the alternative should be adopted. EPA or states can, however, broaden the range of mandatory issues to include particular classes of alternatives, including those that would "redefine the source." As noted, EPA and some states have done so with respect to environmental justice.[118] Some states also have done so as to other matters,[119] such as by establishing an approach to power plant choices that ranks them in ascending order of adverse environmental impacts.[120]

Standing alone, failure to consider a mandatory issue generally would render the permit decision legally deficient.[121] It is important to emphasize, however, that even in the event of a complete failure to consider a mandatory issue or other clear defect in a permit, the aggrieved party is still responsible for pointing out the error and explaining how it renders the permit deficient.[122] Such allocation of burdens is inherent under the arbitrary and capricious standard of review, which presumes the validity of agency action and which places upon a challenger the ultimate responsibility for overcoming this presumption.[123]

In the context of nonattainment areas and NNSR, the allocation of burdens in considering alternatives to the proposed source differs from that under PSD. As noted, NNSR: (1) places an affirmative obligation on the permitting authority to consider "alternate sites, sizes, production processes, and environmental control techniques for such proposed source"; and (2) enables the state to issue the permit only if its analysis "demonstrates that benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification."[124] Using the terms of the analytical framework discussed above, consideration of alternatives is a mandatory permitting element that must be included in the permit application and addressed in the permit decision. Unlike the situation under PSD, consideration of alternatives is never a discretionary issue that commenters have the obli-

114. 1999 EPA App. LEXIS 2, at *127.

115. *Id.* at *128.

116. The claim involved a proprietary process for fiberglass manufacturing. *See id.* at **37-41.

117. *Id.* at *47.

118. *See, e.g.*, Exec. Order No. 12898, *supra* note 109; New York Dep't of Envtl. Conservation, Commissioner's Policy, Environmental Justice and Permitting (2003), *available at* http://www.dec.state.ny.us/website/ej/ejpolicy.html. As previously noted, failure to follow policies adopted by executive order are not judicially reviewable as such. *See supra* note 110. Such disregard of an agency's own decisionmaking criteria would, however, appear to constitute evidence of arbitrary action subject to judicial review on that basis. *But see* Air Transp. Ass'n of Am. v. FAA, 169 F.3d 1, 8-9 (D.C. Cir. 1999).

119. *See infra* note 134 (summarizing Wisconsin resource planning statute).

120. For the reasons discussed, whether a proposed alternative constitutes an attempt to "redefine the source" is not necessarily determinative of either the initial allocation of burden to present that alternative in the permit proceeding or the degree of discretion ultimately afforded to the permitting authority in considering that alternative. Consequently, the term is of limited utility and is potentially misleading. Thus, it would seem prudent for the EAB to discontinue use of the term altogether, or take care to characterize the issues before it in terms of the allocation of the initial burden to address alternatives to a proposed source and related matters.

121. *See, e.g.*, Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co., 463 U.S. 29, 43, 13 ELR 20672 (1983) (normally, an agency action would be arbitrary and capricious if the agency, inter alia, "entirely failed to consider an important aspect of the problem"); Sierra Club v. Leavitt, 2004 U.S. App. LEXIS 8832 (11th Cir. 2004) (same).

122. *E.g.*, Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council, 435 U.S. 519, 553, 8 ELR 20288 (1978).

123. *See, e.g.*, Alaska Dep't of Envtl. Conservation v. EPA, 124 S. Ct. 983, 1004-05, 34 ELR 20012 (2004); Citizens of Overton Park v. Volpe, 401 U.S. 402, 415, 1 ELR 20110 (1971); *see also, e.g.*, City of Seabrook v. EPA, 659 F.2d 1349, 1360, 11 ELR 21058 (5th Cir. 1981) ("[W]hen petitioners claim that an agency conclusion was arbitrary because there was no evidence to support it, they must at least identify the factual determination the agency was required to make and their basis for disputing it, bringing the countervailing evidence, if any, to the attention of the court.").

124. CAA §173(a)(5); *see supra* note 79 and accompanying text.

gation to raise in the first instance, at least as to obvious, reasonable alternatives.

Consequently, the failure to adequately consider alternatives in NNSR permitting should itself be sufficient to render the permit deficient.[125] Where, however, the absence of an alternatives analysis is challenged in judicial review of a permit decision as a failure to undertake a mandatory permitting requirement under NNSR, an aggrieved party still is not relieved of the obligations inherent in any attempt to overturn agency action under the arbitrary and capricious standard of review. Such a party must still explain how this failure bears upon the adequacy of the final permit decision, just as it must "make the case" under PSD.

Even where consideration of alternatives is mandatory, as it always is under nonattainment area NNSR, and sometimes is under PSD, the question remains what constitutes adequate consideration. As noted, EPA has issued no regulations or guidance.[126] What remains is broad discretion for permitting authorities to provide content to this requirement. In these circumstances, some states may be inclined to take a minimalist view of their NNSR obligation, and it could follow that reviewing courts might have little basis upon which to conclude that the state's minimalist treatment was inadequate. As discussed in the next subsection, however, a permitting authority's consideration of alternatives does not occur in a vacuum despite the absence of EPA or state guidance. Instead, it is informed by the statutory language and purposes, as well as by any prior environmental analyses performed for other purposes. Nevertheless, as a practical matter, even in nonattainment areas, those wanting a robust consideration of alternatives to a proposed source would be wise to provide detailed comments supporting their preferred alternatives.[127]

C. The Role of Previously Conducted Environmental Analyses in Considering Alternatives Under NSR

Whether addressing alternatives in the first instance in a permit application or draft permit, or responding to comments that present alternatives, an obvious source of guidance to inform the adequacy of a state's consideration is a previously conducted environmental impacts analysis. Thus, permitting authorities often rely on environmental analyses conducted under state law, such as state equivalents to NEPA, or power plant siting statutes and other resource planning tools.[128] The Energy Policy Act of 1992 required states to at least consider adopting integrated resource planning that considers a range of alternatives in addressing electricity generation.[129] These can be an acceptable means of framing the consideration of alternatives for NSR purposes; a prior environmental impact assessment *can* appropriately inform the preconstruction review.[130]

Reliance on prior analyses of alternatives is adequate in practice, however, only to the extent that: (1) the prior analysis actually addresses all of the issues that would be germane to the permit decision; and (2) the permitting authority exercises independent judgment in the permit decision, and does not automatically accept prior determinations made for other purposes.[131] Thus, if the prior environmental analysis is narrower in scope than is needed for NSR purposes, or failed to incorporate air quality-related data that were not available until submission of the NSR permit application, the prior analysis should be supplemented as necessary. Likewise, if a prior analysis was not informed by all the factors that are relevant to an NSR decision, the permitting authority may not disclaim the ability to reach conclusions different from any that accompanied such prior analysis.[132]

In sum, permitting authorities cannot properly take an "easy way out" when faced with potentially controversial alternatives to a proposed new source by claiming a lack of

125. *See, e.g.*, Oregon Envtl. Council v. Oregon Dep't of Envtl. Quality, 1992 U.S. Dist. LEXIS 14842 (D. Or. 1992) (in citizen suit under CAA §304 collaterally challenging prior state permit decision, permitting authority violated SIP by issuing permits that failed to include NNSR alternatives analysis).

126. *See supra* note 80 and accompanying text. In at least one instance, however, an EPA regional office has construed the NNSR alternatives analysis as providing that the applicant "should provide a thorough alternatives analysis that details alternative locations for the equipment and alternate processes that might have less severe impacts on environmental and public health and safety." *See* Communities for a Better Env't v. Cenco Ref. Co., 180 F. Supp. 2d 1062, 1071 (C.D. Cal. 2001); *see also* In re Campo Landfill Project, 6 E.A.D. 505, ELR ADMIN. MAT. 40526, 1996 EPA App. LEXIS 25, at **36-47 (June 19, 1996) (EIS conducted under NEPA was sufficient for purposes of NNSR alternatives analysis under facts of the case).

127. *City of Seabrook* is instructive in this regard. The case arose under the CAA as amended in 1977, under which only certain nonattainment areas were required, pursuant to CAA §172(b)(11)(A), 42 U.S.C. §7502(b)(11)(A) (1977), to undertake the analysis now mandated in all nonattainment areas pursuant to §173(a)(5) of the CAA as amended in 1990. Petitioners had alleged that the Texas NNSR program was deficient because it merely required permit applicants to state whether an alternatives analysis had been conducted, and contained no specific analytical requirements whatsoever. 659 F.2d at 1361. The court noted both the absence of any EPA guidance or interpretation regarding the content of an alternatives analysis, and that petitioners had made only conclusory allegations of state program deficiency rather than asserting any particular shortcomings. *Id.* at 1359-60, 1363. The court, in a somewhat tortured analysis, reluctantly concluded ("[w]e hesitate to accept the EPA's argument in full," *id.* at 1362) that EPA's approval of the state's bare-bones approach to the analysis requirement was not arbitrary or capricious. *Id.* at 1363.

128. For example, in Wisconsin, the Public Service Commission generally must consider whether a proposed utility plant would satisfy the reasonable needs of the public for an adequate supply of electricity under WIS. STAT. §196.491(3)(d)2, and whether the design and location of the plant is in the public interest considering alternative sources of supply or engineering or economic factors pursuant to *id.* §196.491(3)(d)3. These analyses are incorporated into the PSD permitting decision.

129. *See* 16 U.S.C. §2621(d)(7).

130. *See, e.g.*, [San Francisco] Bay Area Air Quality Management District Rule 2-2-401 addressing the California Environmental Quality Act (CEQA): "[A]pplications for authorities to construct facilities subject to Rule 2 shall include . . . CEQA-related information which satisfies the requirements of Regulation 2-1-426." Regulation 2-1-426 in turn requires the lead agency under CEQA to prepare an [environmental impact report (EIR)]. PSD delegation agreements between EPA and state permitting agencies provide that "where the delegate agency does not have continuing responsibility for managing land use, it shall consult with the appropriate State and local agency primarily responsible for managing land use prior to making any determination under this section." 40 C.F.R. §52.21(u)(2). *See also supra* note 126 and *infra* Section III.A. (discussing role of prior environmental analyses).

131. For example, in In re Sutter Power Plant, 8 E.A.D. 680, ELR ADMIN. MAT. 41216 (EAB Dec. 2, 1999), the EAB rejected a claim that the PSD permit decision failed to consider alternate sites for the proposed source, pointing out that a prior siting analysis under NEPA and California law had considered potential alternatives, and that petitioner had failed to demonstrate that the prior analysis was inadequate or that the permit decision was unreasonable under the record of the case.

132. *See supra* note 94 and accompanying text.

authority to even consider alternatives. Rather, states can be called upon to confront basic issues such as the need for and fundamental design of power plants, to take a public position on those issues, and to be prepared to defend the merits of their positions. In PSD areas, it usually is the obligation of commenters to marshal the facts and arguments supporting their preferred alternatives and present them to the permitting agency. Permitting authorities can, however, by policy, regulation, or statute make consideration of certain alternatives a mandatory part of the preconstruction review. In nonattainment areas, it is always necessary for the permit application to include alternatives to the proposed source, and for the state to consider these alternatives. In both PSD and NNSR permitting, citizens should be prepared to present their preferred alternatives and arguments in support of them. All of this is fully consistent with specific statutory provisions and the underlying legislative intent of the CAA, relevant case law, and basic tenets of administrative law.

III. Considering Alternatives: The Factors That Should Be Addressed in Reviewing Applications for New Power Plants

The foregoing discussion of NSR provisions demonstrates that the framers of the CAA did not intend that PSD and NNSR permit applicants should be entitled to dictate the design parameters under which the prospective major new or modified source of air pollution would be constructed and operated. Likewise, it is clear that permitting authorities are not compelled to grant a permit application that meets a predefined set of specific technical requirements regarding control technology hardware and impacts on ambient concentrations of regulated air pollutants, where broader environmental impact concerns remain. Nevertheless, as a practical matter, in most industries there may be little reason to question a company's basic decision to build. That decision is a result of highly complex market forces. Permitting authorities will likely remain reluctant to question the threshold question of the need for or function of most industrial plants. Likewise, citizens will find it difficult to challenge most such decisions given their highly discretionary nature.[133]

Power plants, however, are different. Because the function of any single plant typically is to add to a common pool of electricity supply, the threshold question of need should never be ignored in deciding whether to issue a permit. Thus, despite a significant degree of economic deregulation in recent years, and the growth of "merchant" plants that sell electric power in the wholesale market, electricity generating plants primarily serve as and are regulated as public utilities. Coal-fired plants in particular merit extra scrutiny because of their tremendous size, longevity, capital and operating costs, demands on fuel suppliers and transmission lines, and adverse environmental impacts. All these public policy concerns are best addressed by reading the CAA as providing no vested right to build a coal-fired plant in any form, and as requiring that every decision to do so only be made after careful consideration of each important aspect of the consequences of that decision. As discussed below, this reading is also the best one under the law.

As explained above, BACT can be a combination of all the available methods for minimizing emissions. These methods are most appropriately addressed in a hierarchical fashion, as it is the clearest method of considering the full range of means to limit air pollution. Some states have expressly adopted such a hierarchical approach to energy planning, under which conservation is considered first and burning of coal last, with other options in-between.[134] Where such policies exist, they should be reflected in an NSR permit application. Where these policies are lacking, interested parties should bring the full range of options to the table in particular permit proceedings, as alternatives to the proposed source.

The following subsections outline, in hierarchical order, the range of emissions issues that should arise in assessing alternatives to a proposed source. The example of a coal-fired power plant is used, although most of the concepts are applicable to other types of power plants and other source categories. Note that although for the reasons explained previously, a hierarchical approach to these emissions reduction methods can facilitate the analysis, it is not a substitute for sound judgment. Nor should a hierarchical approach obscure the need to consider cross-cutting issues. Perhaps most prominent among these are environmental justice and siting issues.[135]

A. Energy Efficiency and Renewable Energy Resources: The Threshold Decision to Build Any New Power Plants Using Fossil Fuels

The threshold question in considering any prospective new or modified electricity generating plant fired by fossil fuels is why the plant should be constructed at all: obviously, it is preferable from the air quality standpoint to rely on renewable energy and more efficient use of existing resources than it is to construct any new fossil-fuel plant. In cases involving traditionally regulated public utilities, a public service commission generally requires a needs analysis. Many states have adopted some form of integrated resource planning that calls for consideration of alternatives to a proposed new power plant, including demand-side management and other

133. As *In re Knauf* illustrates, however, it does not follow as to industrial sources generally that states should take a hands-off approach to questions of production processes, materials and fuels, and efficiency where alternatives would still accommodate production of the intended amount of the desired end product.

134. For example, Wisconsin has adopted an express hierarchy of energy source priorities in WIS. STAT. §1.12 (2002), as follows:

> (4) PRIORITIES. In meeting energy demands, the policy of the state is that, to the extent cost-effective and technically feasible, options be considered based on the following priorities, in the order listed:
>
> (a) Energy conservation and efficiency.
> (b) Noncombustible renewable energy resources.
> (c) Combustible renewable energy resources.
> (d) Nonrenewable combustible energy resources, in the order listed:
> 1. Natural gas.
> 2. Oil or coal with a sulphur content of less than 1%.
> 3. All other carbon-based fuels.

135. Although environmental justice and siting typically are associated with issues closer to the top of the hierarchy, they can involve a mix of emissions reduction methods. For example, the permitting authority might reasonably conclude that it would be preferable to forego construction of a new factory powered by a hydroelectric project that would displace farmers in a minority or low-income community and instead build the factory in another location where power is supplied by a gas-fired turbine even though the latter results in higher emissions. *See also infra* note 202.

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

January 11, 2005

Mr. Michael P. Halpin, P.E.
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Payne Creek Generating Station Peaker Project
Response to FDEP's Second Request for Additional Information
File No. 0490340-003-AC; PSD-FL-344; PA 89-25

Dear Mr. Halpin:

Seminole Electric Cooperative, Inc. (SECI) has received the Department's November 24, 2004 letter requesting additional information regarding the pending August 27, 2004 Air Construction Permit Application for the Payne Creek Generating Station Peaker Project. For your convenience, we have numbered specific responses, below, to correspond with the numbered items in the Department's November 24 letter. In addition, SECI requests the Department's consideration of the following initial observations and information.

At the outset, SECI is very concerned that overall the Department's letter appears to inadequately consider the technical infeasibility and cost-effectiveness information that SECI previously provided in support of this project. SECI submitted its application, including the BACT analysis, in accordance with DEP and EPA approved procedures. When determining BACT, the Department must take "into account energy, environmental, and economic impacts, and other costs". (Rule 62-210.200(38), F.A.C.) Accounting for cost effectiveness distinguishes BACT from the concept of Lowest Achievable Emission Reduction (LAER), which only applies within nonattainment areas. Moreover, certain aspects of the Department's letter articulates an approach to BACT analysis that would have the effect of redesigning the essential elements of the proposed project and forcing SECI to change its proposed fuel option and/or choose an alternative vendor. This is an inappropriate extension of the BACT concept. See In Re Hawaiian Commercial and Sugar Company, (EAB PSD Appeal No. 92-1, 1992)(citing EPA's New Source Review Workshop manual for proposition that BACT review should not redefine the source); In Re Knauf Fiber Glass, Greenbelt, (EAB PSD Appeal Nos. 98-3 through 98-20) (BACT review should not redefine the source).

Regarding the specific project that SECI has proposed, it is very important to note that SECI needs the capability of generating up to 310 MW of electricity in various increments based on peak demand. The Pratt & Whitney FT8-3 aeroderivative combustion turbines are self contained, multi-fuel generating units that offer a very unique ability to supply precise amounts of peaking electrical energy using natural gas and oil while operating at their highest efficiency level. More specifically, each water-injected FT8-3 Twin Pac can generate up to 62 MW of electricity while NOx emissions are maintained at 25 ppm (gas) and 42 ppm (oil), and each individual water-injected turbine can operate as low as 12.5 MW while maintaining NOx emissions at the same levels. This modularity satisfies SECI's unique need to meet the peak electricity demands of its members at precise and highly efficient energy output levels while also consistently controlling emissions. The ability to burn both natural gas and fuel oil is essential to both SECI's and Florida's need for fuel diversity, electric reliability, and flexibility. Unlike large mainframe combustion turbines, the Pratt & Whitney FT8-3 units can be cycled on a daily basis without the requirement to undergo accelerated, expensive maintenance overhauls. Again, this enhances reliability. Another important aspect of the proposed project design is that the units can go from a cold start to full load in less than 10 minutes. This capability will enable SECI to follow its peak load using these efficient units in small increments instead of starting large mainframe combustion turbines and running them at lower, less efficient, loads. The 10-minute start time also enables SECI to count a portion of the FT8-3 capacity towards its state-mandated spinning reserve requirement. This eliminates the need to rely on larger generating units from other companies to be on-line to provide this spinning reserve capacity.

In sum, SECI thoughtfully selected the Pratt & Whitney aeroderivative design based on its ability to run at very low loads (12.5 MW) and meet specific efficiency needs while maintaining compliance with applicable emissions limitations. These features will enable a more efficient operation with lower overall air emissions. In addition, the FT8-3 can meet its higher load outputs without the need for an inlet heating and cooling system. An especially beneficial feature of the FT8-3 turbines is the Pratt & Whitney program that enables a user to temporarily replace a damaged engine within 96 hours. Even while the damaged engine is being replaced, the Twin Pac unit can still operate at one-half the output while maintaining its high efficiency and low emissions at 25/42 ppm NOx when firing natural gas/distillate fuel oil. This minimizes the potential adverse impacts to SECI's customers and to other state generating sources that supply replacement power during forced unit outages.

Attachment E to SECI's application provided summaries of national BACT determinations. Our research indicates that of over 258 FT8s constructed around the world since 1992, only 22 were installed with SCR. Most recently, eleven Twin Pacs were permitted in North Carolina, five in Virginia, six in West Virginia, five in Pennsylvania, six in Illinois, four in Ohio, two in Oregon, one in Minnesota, one in Michigan, one in Wisconsin, and four in Indiana, all without SCR. Especially relevant to the SECI project are four FT8 Twin Pacs in Missouri (two at Empire Electric and two at City Utility of Springfield) and two in Nebraska (Omaha Public Power District), which underwent BACT analysis and were permitted with water injection at 25/42 ppm (all of these projects with the exception of the City Utility of Springfield, MO were included in SECI's Application, Attachment E, page E1-2).

Following are SECI's specific responses to the Department's November 24 letter:

(1) The Standard Energy Ventures (SEVs) project permitted by Illinois EPA (IEPA) is not a legitimate precedent for determining BACT for SECI's proposed project. It should be noted that the SEV project was located in a nonattainment area for ozone, and that SEV in the first instance proposed SCR as a feature of the proposed project, which consisted of 16 Twin Pacs at one site, gas-fired only. (Whereas SECI is applying for 5 Twin Pacs firing oil and gas in an attainment area.) Potential NOx emissions from the SEV project, when considering the SCR, were lower than major source levels, and therefore, NSR did not apply; BACT for NOx, therefore, was not formally presented by SEV or determined by IEPA. Moreover, if the SEV project had been major for NOx, the NOx limit would have been based on LAER because of the ozone nonattainment status, which as stated above, does not consider cost. Finally, we understand that the SEV project (which included SCR) was never constructed because it turned out to be economically infeasible. The SEV construction permit has expired. Also, it is noteworthy that the EPA letter appended to your November 24, 2004 Request for Additional Information is not a BACT determination and clearly acknowledges that in any given circumstance the permittee may demonstrate economic infeasibility.

(2) The Granite Power Partners Hardee County Generation Facility is distinguishable from SECI's project in several important respects that significantly diminish its relevance/value as a precedent:

A. The Hardee County Generation Facility (HCGF) was a speculative merchant project proposed by an independent power producer, Granite Power Powers (GPP). Although issued an air construction permit by the Department (Permit No.: PSD-FL-281) in August 2000, the project was not constructed and the PSD permit expired.

B. Whereas the SECI project consists of five (5) Pratt & Whitney FT8-3 Twin Pac aeroderivative CT units (each FT8-3 Twin Pac unit is comprised of two simple cycle combustion turbines coupled to one common generator having a nominal generation capacity of 62 MW), the speculative HCGF project was proposed as three dual-fuel simple cycle frame-type combustion turbines with nominal power output capacities ranging from 120 to 170 MWs per turbine. These proposed large frame-type CTs would have had significantly different design and exhaust characteristics compared to the nominal 31 MW Pratt & Whitney aeroderivative CTs planned for the Payne Creek Generating Station.

C. At the time of its air construction permit application submittal, GPP had not selected a particular CT vendor for its speculative HCGF project. For this reason, the submitted air permit application addressed the following four CT vendors or types: (a) General Electric (GE) nominal 170 MW 7FA units, (b) Siemens Westinghouse (S/W) nominal 170 MW 501F units, (c) S/W nominal 120 MW 501D5A units, and (d) ABB nominal 180 MW GT-24 units. In its comments to the Department on the agency's draft PSD permit, GPP withdrew the ABB GT-24 CT option from further permitting consideration. Accordingly, GPP did not consider it necessary or appropriate to assess or dispute any of the Department's BACT comments regarding the ABB GT-24 CT.

D. While there were differences in expected NOx emission rates for the various frame-type simple cycle CTs (i.e., the GE, S/W, and ABB units) considered by GPP at the time of submittal of the HCGF air construction permit application, the three major vendors of simple cycle aeroderivative CTs (GE, P&W, and Rolls-Royce) all currently offer units with guaranteed NOx exhaust concentrations no lower than 25 ppmvd NOx when firing natural gas and 42 ppmvd when firing distillate fuel oil.

(3) SECI's proposed FT8-3 units feature conventional combustors that include water injection for power augmentation and NOx reduction. The cost reduction to remove the water injection system from the gas turbine package is approximately $200,000 per FT8-3 Twin Pac. The cost reduction to remove the water injection balance of plant systems would be approximately $1,025,000 per FT8 Twin Pac, installed, based on a five-unit plant (see attached Pratt & Whitney document). Significantly, however, the FT8-3 units without water injection produce a NOx level of around 200 ppm on natural gas fuel. We are not aware of any aeroderivative CT manufacturer that has installed CTs with NOx guarantees less than 25 ppm on gas fuel without an SCR. The NOx output with water injection is 25 ppm on natural gas fuel and 42 ppm on liquid fuel. Also note that removal of water injection results in a substantial energy penalty (due to lost power-augmentation capability) and lost ability to fire fuel oil, which would necessitate adding another Twin Pac to generate the needed 310 MW. Construction of another Twin Pac would cost SECI approximately $16,200,000 plus balance of plant capital costs and installation as detailed below in response number 5.

SECI also wishes to state its understanding of emission levels at a Cal Peak facility in California. Our information is that this facility is achieving NOx levels prior to the SCR around 36-38 ppm when firing natural gas, but this is not an uncontrolled unit. These machines are FT8-2s which are equipped with DLN. Pratt & Whitney is not aware of an uncontrolled FT8 in the United States, and stands by its emission estimates stated in the paragraph above and in the attachment.

(4) As stated above, the combustion turbines that meet SECIs needs are FT8-3 units with conventional combustors. The only FT8 units available with a DLN combustor are the FT8-2, which has 15% less power on a hot day, plus the loss of power augmentation capability associated with water injection. Expected NOx levels when burning natural gas with DLN combustors are higher than the water injected 25 ppm level. The FT8-2 DLN gas turbine is a gas-only machine; it has no liquid fuel capability. The additional cost to convert the FT8-3 to a FT8-2 (DLN) is $1,464,600 per FT8 Twin Pac (see attached Pratt & Whitney document). Losing power-augmentation capability and the

capability to fire fuel oil would be inconsistent with SECI's generation and reliability requirements, and would require at least one additional FT8-3 unit.

(5) Pratt & Whitney has provided in the past a 90% efficient NOx reduction system. The NOx level into the SCR, when firing gas, is 25 ppm and the outlet is 2.5 ppm. The NOx level into the SCR, when firing oil, is 42 ppm and the outlet is 4.2 ppm. The total system back pressure including the ductwork and SCR is 15" H2O (this pressure drop is calculated at the end of the catalyst life). The as-purchased FT8-3 with a CO Catalyst has a total system back pressure of 5.0" H2O. The additional 10" H2O of backpressure for the SCR relates to a 1.5% decrease in power and a 1.5% increase in heat rate. The amount of ammonia required is 185 lbs/hr with an ammonia slip of 10 ppm (see attached Pratt & Whitney document). Based on these assumptions, the cost effectiveness is $13,329 per ton of NOx controlled using EPA factors for typical SCR direct installation costs. The cost effectiveness is $16,340 per ton of NOx controlled using the higher site-specific SCR direct installation cost estimate.

SECI is in the process of selecting the construction/installation contractor, and based on prior construction experience, estimates the installation cost for the 5 Twin Pacs at the Payne Creek site to be $12,270,000 or approximately $2,454,000 per Twin Pac. As provided in the attached Pratt & Whitney letter, the additional installation cost per SCR per Twin Pac at the Payne Creek site is $2,100,000 or $10,500,000 for 5 Twin Pacs. The Payne Creek Generating Station is located on reclaimed phosphate land, and the site specific soil conditions will require approximately (20), 30-foot piles per SCR foundation, which significantly increases the SCR installation cost at this site.

The total cost of the facility without SCR's is estimated at $134,000,000. This total cost consists of three primary components: capital equipment, installation, and owners costs. The total capital equipment cost for the project is $104,255,000 and consists of: $88,000,000 for the 5 Pratt & Whitney Twin Pacs, and $16,255,000 for the balance of plant capital equipment. Installation costs are those costs directly related to installing the capital equipment and are estimated to be $12,270,000, as described above. Owners costs are estimated to be $17,475,000 and consist of various items such as: permitting, start-up costs, interest during construction and spare parts. If SCR's were added to the scope of the project, the total cost would increase by $22,513,000 to $156,513,000.

(6) SECI has received no response to date regarding its December 6, 2004 letter requesting to review "all information at [your] disposal" that the Department apparently intends to utilize to internally estimate the cost effectiveness of hot SCR. SECI looks forward to the Department's response.

Thank you for your attention to this information and we look forward to working with you in coming to a determination as expeditiously as possible. Please feel free to contact me at (813) 963-0994.

Sincerely,

M.P. Opalinski

Michael P. Opalinski
Vice President of Technical Services

Cc:
Trina Vielhauer, DEP
Jim Pennington, DEP
Jim Frauen, SECI
Tom Davis, ECT
Jerry Kissel, SWD
Buck Oven, PPSO
Gregg Worley, EPA Region 4
John Bunyak, NPS
Jim Alves, HGS
Robert Manning, HGS

Pratt & Whitney Power Systems, Inc.

80 Lamberton Road
Windsor, CT 06095
(860) 565-3339

Pratt & Whitney
A United Technologies Company

January 11, 2005

Mr. Trevor Pannell
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, FL 33688

Ref: Payne Creek Peaker Project
FDEP Request for Additional Information

Dear Trevor:

As requested, responses to the issues raised by the Florida Department of Environmental Protection (FDEP) to Seminole Electric Cooperative, Inc. pertinent to Pratt & Whitney are provided as follows:

The additional Twin PAC **Equipment Only** Price would be **$16,200,000**

The gas turbines that Seminole Electric has purchased are FT8-3 units with conventional combustors. The only FT8 available with a DLN combustor is the FT8-2, which has 15% less power on a hot day, plus the loss of power augmentation due to water. The NOx gas fuel level is no better than the water injected 25-ppm level. The FT8-2 DLN gas turbine is a gas only machine and **has no liquid fuel capability**. FT8 -2 (DLN) is **$1,464,600** per FT8 Twin PAC additional **Equipment Only** Price for a total **Equipment Only** price of **$ 7,323,000** for all five Units.

The typical SCR system that PWPS has provided in the past is a 90% efficient NOx reduction system. The gas fuel NOx into the SCR is 25 ppm and the outlet is 2.5 ppm. The liquid fuel NOx into the SCR is 42 ppm and the outlet is 4.2 ppm. The total system backpressure including the ductwork and SCR is 15" H2O (This pressure drop is calculated at the end of the catalyst life.) The as purchased FT8-3 with CO Catalyst has a total system back pressure of 5.0" H2O. The additional 10" H2O of backpressure for the SCR relates to a 1.5% decrease in power and a 1.5% increase in heat rate. The amount of ammonia required is 185 lbs/hr with an ammonia slip of 10 ppm. The catalyst life would typically be 3.5 years. The SCR system is estimated at **$2,402,600** per Twin PAC and can be installed for **$2,100,000** per Twin PAC at the Seminole Site. At Seminole the soil conditions will require approximately (20), 30-foot piles per SCR foundation. This is a costly installation.

The FT8-3 units without water injection result in a NOx level of 200-ppm on natural gas fuel. The cost savings to remove the water injection system from the gas turbine package is $200,000 per FT8 Twin Pac. The cost savings to remove the water injection balance of plant systems would be approximately $ 1,025,000 per FT8 Twin Pac.

I have attached a typical data sheet for a SCR that would be used on an FT8-3 on gas.

Please contact me if any you have any questions or need any additional information.

Sincerely,

Mark S. Etre
Project Manager

Cc: 0302 Contract File
Attached: 1) Typical SCR Data Sheet

DESIGN CRITERIA

The proposed SCR System design is based on the following design conditions; the data is for one (1) unit. Should the actual gas conditions be different from the design data, the performance shall be re-evaluated, based on the corrected design data.

ITEMS	UNITS	DESIGN CONDITIONS			
CASE DESCRIPTION:		**Case 1 – 59F**	**Case 2 – 91F**	**Case 3 – 91F**	**Case 4 – 104F**
FUEL:		NG	NG	NG	NG
REACTOR INLET CONDITIONS:					
Flue Gas Flow Rate, Wet	lb/hr	1,444,320	1,331,280	1,355,040	1,271,520
Design Maximum Temp	°F	905	938	933	956
Flue Gas Composition:					
O_2	vol % wet	13.02	12.53	12.46	12.18
H_2O	vol % wet	10.5	12.97	13.19	14.64
N_2	vol % wet	72.33	70.39	70.22	69.08
CO_2	vol % wet	3.28	3.27	3.28	3.27
Ar	vol % wet	0.86	0.84	0.84	0.82
Trace Components:					
NO_X	ppmvd	25.0	25.0	25.0	25.0
NO_X	lb/hr	56.9	52.7	53.9	50.7
CO	ppmvd	80.0	80.0	80.0	80.0
CO	lb/hr	111	103	105	98.8
$DeNO_X$ Efficiency	%	90.0	90.0	90.0	90.0
CO Oxidation Efficiency	%	90.0	90.0	90.0	90.0
Dilution Exhaust Gas	lb/hr	2,633	2,633	2,633	2,633
Aqueous NH_4OH Consumption	lb/hr	144	133	136	128
Aqueous NH_4OH Consumption	gallons/ month	12,952	11,996	12,273	11,535
REACTOR OUTLET CONDITIONS:					
Flue Gas Flow Rate, Wet	lb/hr	1,477,097	1,334,046	1,357,809	1,274,281
Performance Guarantees:					
NO_X	ppmvd	2.5	2.5	2.5	2.5
NO_X	lb/hr	5.7	5.3	5.4	5.1
CO	ppmvd	8.0	8.0	8.0	8.0
CO	lb/hr	11.1	10.3	10.5	9.9
NH_3	ppmvd	≤ 10	≤ 10	≤ 10	≤ 10
Estimated System Pressure Drop	"W.C.	<17.5" H2O			

The proposed SCR System design is based on the following design conditions; the data is for one (1) unit. Should the actual gas conditions be different from the design data, the performance shall be re-evaluated, based on the corrected design data.					
ITEMS	**UNITS**	**DESIGN CONDITIONS**			
CASE DESCRIPTION:		**Case 5 – 104F**	**Case 6 – 59F**	**Case 7 – 91F**	**Case 8 – 91F**
FUEL:		NG	No. 2 Fuel Oil	No. 2 Fuel Oil	No. 2 Fuel Oil
REACTOR INLET CONDITIONS:					
Flue Gas Flow Rate, Wet	lb/hr	1,310,400	1,411,200	1,313,280	1,345,680
Design Maximum Temp	°F	947	886	942	934
Flue Gas Composition:					
O_2	vol % wet	12.11	13.39	12.66	12.60
H_2O	vol % wet	14.89	8.54	11.31	11.54
N_2	vol % wet	68.90	72.88	70.75	70.59
CO_2	vol % wet	3.28	4.31	4.42	4.43
Ar	vol % wet	0.82	0.87	0.84	0.84
Trace Components:					
NO_X	ppmvd	25.0	42.0	42.0	42.0
NO_X	lb/hr	52.5	92.9	89.6	92.0
CO	ppmvd	80.0	14.0	12.0	12.0
CO	lb/hr	102	18.8	15.6	16.0
$DeNO_X$ Efficiency	%	90.0	90.0	90.0	90.0
CO Oxidation Efficiency	%	90.0	85.7	83.3	83.3
Dilution Exhaust Gas	lb/hr	2,633	3,943	3,943	3,943
Aqueous NH_4OH Consumption	lb/hr	133	206	198	204
Aqueous NH_4OH Consumption	gallons/ month	11,934	18,497	17,845	18,334
REACTOR OUTLET CONDITIONS:					
Flue Gas Flow Rate, Wet	lb/hr	1,313,166	1,415,349	1,317,421	1,349,827
Performance Guarantees:					
NO_X	ppmvd	2.5	4.2	4.2	4.2
NO_X	lb/hr	5.2	9.3	9.0	9.2
CO	ppmvd	8.0	≤2.0	≤2.0	≤2.0
CO	lb/hr	10.2	≤2.7	≤2.6	≤2.7
NH_3	ppmvd	≤10	≤10	≤10	≤10
Estimated System Pressure Drop	"W.C.	<17.5" H2O			

The proposed SCR System design is based on the following design conditions; the data is for one (1) unit. Should the actual gas conditions be different from the design data, the performance shall be re-evaluated, based on the corrected design data.					
ITEMS	**UNITS**	**DESIGN CONDITIONS**			
CASE DESCRIPTION:		**Case 9 – 104F**	**Case 10 – 104F**		
FUEL:		No. 2 Fuel Oil	No. 2 Fuel Oil		
REACTOR INLET CONDITIONS:					
Flue Gas Flow Rate, Wet	lb/hr	1,257,840	1,288,800		
Design Maximum Temp	°F	959	952		
Flue Gas Composition:					
O_2	vol % wet	12.31	12.24		
H_2O	vol % wet	13.00	13.25		
N_2	vol % wet	69.44	69.25		
CO_2	vol % wet	4.42	4.44		
Ar	vol % wet	0.83	0.82		
Trace Components:					
NO_X	ppmvd	42.0	42.0		
NO_X	lb/hr	86.3	88.8		
CO	ppmvd	11.0	11.0		
CO	lb/hr	13.8	14.2		
$DeNO_X$ Efficiency	%	90.0	90.0		
CO Oxidation Efficiency	%	81.8	81.8		
Dilution Exhaust Gas	lb/hr	3,943	3,943		
Aqueous NH_4OH Consumption	lb/hr	191	196		
Aqueous NH_4OH Consumption	gallons/ month	17,189	17,681		
REACTOR OUTLET CONDITIONS:					
Flue Gas Flow Rate, Wet	lb/hr	1,261,974	1,292,939		
Performance Guarantees:					
NO_X	ppmvd	4.2	4.2		
NO_X	lb/hr	8.6	8.9		
CO	ppmvd	≤2.0	≤2.0		
CO	lb/hr	≤2.5	≤2.6		
NH_3	ppmvd	≤10	≤10		
Estimated System Pressure Drop	"W.C.	<17.5" H2O			

DESIGN NOTES	
1	"ppmvd" denotes parts per million by volume, dry, referenced to 15 percent oxygen.
2	The **aqueous** ammonia must be industrial or technical grade, diluted with **fully de-ionized** water to 19% by weight.
3	To prevent premature thermal degradation of the SCR catalyst, the temperature at the catalyst face must not exceed 930°F.
4	The SCR catalyst face temperature must be a minimum of 450°F for natural gas before ammonia injection will be allowed.
5	The NO/NOx ratio at the AIG and catalyst must be greater than 0.50 at the SCR inlet for optimum performance and NO_X reduction guarantees to be met.

B. GENERAL SPECIFICATIONS:

	DESCRIPTION
1	**Electrical Classification:** NEMA 4 non-hazardous

C. UTILITY CONSUMPTION:

DESCRIPTION		UNITS
Aqueous Ammonia (19% by Weight)		
Flow Rate	206	Lbs/Hr/Unit
Supply Pressure	40	PSIG
Inlet Temperature	40	F Minimum for NH_3
Inlet Temperature	0-100	F for NH_4OH
Electric Air Heater, 3-Phase, 480V, 60 Hz		
Capacity	Modified to 180	kW
Consumption at Above Ammonia Flow Rate (Estimated)	TBD	kW
Instrument Air (-20 F Dew Point or Better)		
Supply Pressure	80-100	PSIG
Maximum Steady State Air Consumption	0.5	SCFM
Maximum Steady State Air Supply Demand	5	SCFM
Dilution Exhaust Air Blowers, 480V, 3-Phase, 60 Hz		
Nominal Motor Rating	20	HP
Operating Power Consumption (Estimate)	30 – 40% of rated capacity	BHP
Cooling Air Blowers, 480V, 3-Phase, 60 Hz		
Nominal Motor Rating	150 (existing)	HP
Operating Power Consumption (Estimate)	30 - 40% of rated capacity	BHP
Control Power, 120V, 1-Phase, 60 Hz		

D. CATALYST:

SCR CATALYST DATA			
Catalyst Manufacturer	Hitachi America or Equal		
Catalyst Type	Plate		
Gas Flow	Horizontal		
Number of Modules	TBD		
Module Size W x H x D	TBD		
Total Catalyst Weight	66,000 lb.		
Estimated Internal Structure W x H x D	16' x 36'		
Estimated Pressure Drop	≤5.5 "H_2O		

CO CATALYST DATA			
Catalyst Manufacturer	Engelhard or Equal		
Catalyst Type	Pt		
Gas Flow	Horizontal		
Total Catalyst Weight	TBD		
Estimated Internal Structure W x H	16' x 36'		
Estimated Total Pressure Drop	≤2.8 "H_2O		

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

January 20, 2005

Michael P. Opalinski
Vice President of Technical Services
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
PO Box 272000
Tampa, Florida 33688-2000

RE: Payne Creek Generating Station Peaker Project
File No. 0490340-003-AC; PSD-FL-344; PA 89-25

Dear Mr. Opalinski:

I am in receipt of Seminole Electric Cooperative, Inc.'s ("Seminole") January 11, 2005 response to the Department's second request for additional information ("Seminole's letter") for the above reference project. Seminole's letter is currently under review by my staff. I am also in receipt of the December 6, 2004 letter from Mr. Jim Alves referenced in paragraph 6 of Seminole's letter. In both letters, a request is made to review "all information at [your] disposal that the Department apparently intends to utilize to internally estimate the cost effectiveness of hot SCR".

As of today's date, Seminole's application remains incomplete. As I indicated at the December 21, 2004 meeting, the Department is still in the process of evaluating the application, collecting and evaluating appropriate information and documentation, and determining its agency action. Therefore, the Department cannot, at this time, fulfill these requests *as written*. However, if you are interested in conducting a public records review of this application file as it stands on today's date, you are welcome to do so. Please understand that the Department reserves its right to collect, utilize and rely upon any additional information it identifies and deems relevant prior to its proposed agency action. You may arrange a public records review of these files by contacting Ms. Patty Adams at 850/921-9505.

Sincerely,

Trina L. Vielhauer

Trina L. Vielhauer
Chief
Bureau of Air Regulation

cc: Jim Alves and Robert Manning

SEMINOLE – DEP MEETING AGENDA

Payne Creek Generating Station Peaking Project
December 20, 2004

- Introduction and purpose of today's meeting
  - Concerns about DEP's approach
  - Need for expeditious resolution

- Need for this project
  - Need 310 MW peaking power – 2500 hours (500 on oil)
  - Dual-fuel capability – fuel diversity, reliability issue

- Benefits of P&W Twin Pac units
  - High-efficiency and low-emissions across range of operating levels (from 12.5 to 310 MW)
  - Can meet peak demand in small MW increments (as low as 12.5 MW), which minimizes emissions and lowers cost
  - Capable of higher loads without need to cool or heat inlet air
  - Daily cycling ability without increasing maintenance needs
  - Cold start to full load in 10 minutes
  - Ability to count the FT8-3 capacity toward spinning reserve requirement
  - Ability to rapidly replace engines (within 96 hours), if needed

- BACT analysis
  - Cost considerations
    - Disregarding cost results in LAER
    - Removing water injection results in 200 ppm NOx on gas, and decreased power
    - DLN is not available for dual-fuel and has same 25 ppm as water injection
    - DLN results in 15 percent power loss on a hot day, plus losses due to water-related power augmentation
    - Removing water injection or adding DLN would trigger need for additional units
    - SCR at 90% efficiency results in a 10 inches of water increase in backpressure, a 1.5% decrease in power, a 1.5% increase in heat rate, and 10 ppm ammonia slip
    - Total installation costs are not currently segregated from the total cost of the units
      - SCR installation costs are much higher at Payne Creek site because it is located on reclaimed phosphate land

Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

November 24, 2004

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Michael Opalinski, VP Technical Services
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, FL 33688-2000

Re: Second Request for Additional Information
Payne Creek Generating Station
Peaker Project
File No. 0490340-003-AC; PSD-FL-344; PA 89-25

Dear Mr. Opalinski:

This is in reply to your responses to our Request for Additional Information dated September 23, 2004. In order to continue processing your application, we will need the additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

BACT Determination for NO_X

Notwithstanding the provided cost effectiveness calculations provided by SECI, the Department notes or requests the following information:

1) In a letter written to the Illinois EPA (IEPA) dated July 5, 2000, the USEPA Region 5 spoke to the issue of whether 25 ppm and water injection represented BACT for the control of nitrogen oxides. Region 5 stated that the proposal under evaluation by IEPA for BACT "does not meet the requirements of the Clean Air Act". This memo can be found at: http://www.epa.gov/rgytgrnj/programs/artd/air/nsr/nsrmemos/sev.pdf
2) In a Best Available Control Technology Determination completed by FDEP in year 2000 (PSD-FL-281), where the applicant proposed (as one option) the installation of ABB GT-24 machines with a NOx BACT of 25ppm via water injection, the Department went on record as stating:
   A) "The proposed emission limit of 25 ppmvd NO_X for the ABB GT-24 option is too high compared with the 10.5 limit for the similar class GE product. The added power and efficiency characteristics of the ABB GT-24 do not justify a BACT for NO_X more than twice that of the GE product." and
   B) "BACT for the ABB option is determined to be 5 ppmvd by Hot SCR while firing natural gas. Up to 250 hours of fuel oil operation are permitted with the Hot SCR system off (NO_X equal to 42 ppmvd) and another 250 hours are permitted with the Hot SCR system in operation (NO_X equal to 10 ppmvd)."
3) Please obtain from Pratt & Whitney the reduction in cost, for removal of the water injection option. Additionally, please estimate all related cost reductions for the balance of plant (e.g. water treatment systems, piping, etc) including both fixed and variable costs without water injection.
4) Please identify whether the proposed CT's are fitted with DLN; if not, obtain from Pratt & Whitney the incremental cost for incorporating DLN.
5) Please obtain from Pratt & Whitney a written copy of all available specifications for the quoted SCR. The Department would expect that (at a minimum) NOx inlet and outlet, ammonia demand, back pressure and catalyst life would have all been specified. Additionally, please indicate who (whether or not Pratt & Whitney) SECI intends to contract for the construction, and whether any contractor has

provided SECI with estimated written total installation costs for the 10 simple cycle combustion turbines, with or without SCR. The Department is interested in comparing total installation cost to the SCR installation costs which SECI has calculated.

6) The applicant should be aware that the Department intends to internally estimate the cost effectiveness of Hot SCR, based upon all information at its disposal. One possible outcome is that the Department may determine that the CT's selected by SECI are incapable of meeting current day BACT standards.

Please note that EPA and NPS have been copied on your application, and should FDEP receive questions or comments from them, we will forward you a copy.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): "The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."

If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9519.

Sincerely,

Michael P. Halpin, P.E.

Michael P. Halpin, P.E.
DARM/BAR

Mike Roddy, SECI
Tom Davis, ECT
Jerry Kissel, SWD
Buck Oven, PPSO
Gregg Worley, EPA Region 4
John Bunyak, NPS

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

RECEIVED
NOV 17 2004
BUREAU OF AIR REGULATION

November 10, 2004

Mr. Michael P. Halpin, P.E.
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Payne Creek Peaker Project
FDEP Request for Additional Information

Dear Mr. Halpin:

Seminole Electric Cooperative, Inc. (SECI) has received your letter dated September 23, 2004 requesting additional information with regards to the Payne Creek Generating Station Peaker Project. For your convenience, we have restated each point and provided a response below each specific issue.

Issue No. 1 – BACT Determination for NO_x

<u>40 CFR 63 Subpart YYYY Applicability</u>

The Department's letter indicates that the oxidation catalyst systems proposed for the simple cycle combustion turbines are being installed to comply with the requirements of 40 CFR 63, Subpart YYYY, *National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Stationary Combustion Turbines*. As noted on Page 5-5 of the air construction permit application, the Payne Creek Generating Station (PCGS) is currently a synthetic minor source of hazardous air pollutants (HAPs). The addition of the proposed simple cycle combustion turbines will not change this regulatory classification; i.e., the PCGS will remain a synthetic minor source for HAPs. Since 40 CFR 63 Subpart YYYY is only applicable to stationary combustion turbines located at a major source of HAP emissions, this NESHAPS is not applicable to the PCGS simple cycle combustion turbine project.

<u>SCR Control Costs</u>

Items 1) and 2)

Pratt & Whitney (P&W) has confirmed that the total capital cost of SCR control systems for the ten simple cycle combustion turbines is $11,227,500 based on a deduction of $785,500 for oxidation catalyst control technology. P&W further indicates that the oxidation catalyst deduction is valid only if an order for SCR controls is placed by March 31, 2005, and that thereafter the SCR control cost will be $12,013,000 for the ten simple cycle combustion turbines. P&W has advised that their SCR control cost estimate includes freight and instrumentation but does not include sales tax or installation costs. P&W estimates a total SCR installation cost of $10,500,000 for the ten simple cycle combustion turbines.

Note that the planned CO oxidation catalyst system will be installed in the vertical section of each simple cycle combustion turbine exhaust stack. In contrast, SCR controls would require a separate device to be added to the horizontal section of each combustion turbine exhaust duct and would require extensive exhaust duct modifications to accommodate the control system.

A copy of P&W's written response to these SCR cost issues is provided in Attachment A.

Item 3)

The estimate of SCR control costs was conducted using procedures obtaining from the Environmental Protection Agency's *Air Pollution Control Cost Manual, Sixth Edition* dated January 2002. This edition of the Cost Control Manual includes a new section on SCR control costs – reference Section 4 (NO_x Controls), Section 4.2 (NO_x Post-Combustion Controls), Chapter 2, Selective Catalytic Reduction.

Section 4.2, Chapter 2 indicates on Page 2-47 that the future worth factor (FWF) should be used to calculate the annual catalyst replacement cost. The annual capital recovery cost is the total capital investment (TCI) multiplied by the capital recovery factor (CRF). For a SCR control system, TCI includes the cost of the initial catalyst. When the CRF is also used to calculate annual catalyst replacement costs, it is appropriate to subtract the cost of the initial catalyst from the TCI when calculating the annual capital recovery cost to avoid "double-counting" of catalyst replacement costs since the CRF considers the catalyst replacement cost to be a present value; i.e., incurred at the start of a project. However, the initial catalyst charge is not "double-counted" and should not be subtracted from the TCI if the FWF is used instead of the CRF to calculate the annual catalyst replacement cost since the FWF treats the catalyst replacement cost as an expense that is incurred in the future; i.e., discounts the future catalyst replacement cost for the time value of money. Subtracting the initial catalyst charge from the TCI when the FWF is used for catalyst replacement costs will completely exclude the initial catalyst cost from the economic analysis. A discussion of the FWF with respect to SCR catalyst replacement costs can be found starting on Page 2-6, Section 4.2, Chapter 2 of EPA's Air Pollution Control Cost Manual. An example calculation of SCR control costs is also provided in Chapter 2 starting on Page 2-50. This example does not subtract the initial catalyst cost when calculating the annual capital recovery cost.

analysis excludes freight and instrumentation costs. Conservatively, the EPA Cost Control Manual methodology for estimating installations costs was retained although this procedure results in an installation cost that is well below the P&W estimate. The revised SCR cost effectiveness for the PCGS simple cycle combustion turbine project is $14,654 per ton of NO_x controlled. Note that use of the P&W SCR installation cost estimate yields a cost effectiveness of $18,031 per ton of NO_x controlled.

Issue No. 2 – BACT Determination for SO_2

Item 1)

A copy of P&W's Gas Turbine Liquid Distillate Fuel Requirements is provided in Attachment C to this letter. As shown on Table 1 of this document, the maximum recommended distillate fuel oil sulfur content is 1.3 weight percent.

Item 2)

The requested 500 hours of operation on distillate fuel oil represents SECI's best estimate of the maximum amount of hours that will be needed due to potential interruptions in natural gas supply. This estimate is considered reasonable and prudent in light of the recent natural disasters that Florida has experienced; i.e., Hurricanes Charley, Francis, Jeanne, and Ivan.

With respect to project SO_2 emissions, we have evaluated our premise for the sulfur content of natural gas (2.0 grains of sulfur per one hundred standard cubic feet [gr S/100 ft^3]) and conclude that this estimate significantly over-estimates actual natural gas sulfur contents. Accordingly, project SO_2 emissions have been re-estimated assuming a natural gas sulfur content of 1.0 gr S/100 ft^3. This lower natural gas sulfur content remains conservative; i.e., actual sulfur contents would be expected to be less than approximately 0.5 gr S/100 ft^3. Project SO_2 emissions, based on the revised natural gas sulfur content, total 45.7 tons per year. Revised Pages 23 and 24 of the FDEP Application for Permit – Long Form, and a Professional Engineer certification are provided in Attachment D to this letter.

Item 3)

Our fuel oil supplier, British Petroleum (BP), indicates that they currently do not market ultra low sulfur diesel (ULSD) in the southeast (SE), and that ULSD fuel oil will not likely be available in the SE until late 2005 or mid-2006. BP also reviewed the ULSD oil cost estimates contained in our August 2004 Air Construction Permit Application and found them to be reasonable. Further information regarding BP's ULSD fuel oil can be found on their website at ecdiesel.com.

Item 4)

As noted in the air construction permit application, regional haze impacts at the Chassahowitzka National Wildlife Refuse are considered acceptable for the following reasons:

- Only one 24-hour period out of 1,097 modeled events (1990, 1992, and 1996) exceeded the FLM 5.0 percent guideline; i.e., the guideline was exceeded for only 0.091 percent of the modeled period;
- The regional haze impacts assumed continuous oil-firing. For the SCCT project, oil-firing hours will be limited to no more than 500 hours per year;
- The 5.0 percent FLM guideline is half of the level that is perceptible; i.e. increases in β_{ext} above 10 percent (equivalent to a dv change of 1.0) are considered to be perceptible at the furthest extent of the visual range. Accordingly, the predicted SCCT maximum regional haze impact of 5.14 percent will not be perceptible.
- The regional haze analysis compares project impacts with "natural" background; i.e., a theoretical background that would occur in the absence of all anthropogenic activities. This results in a natural background visual range of approximately 105 miles for the Chassahowitzka NWR. Other than nighttime celestial objects, there are no line-of-sight vistas in the coastal Chassahowitzka NWR that are near this visual range. For example, the theoretical line-of-sight for a six-foot tall person on the shoreline of the Gulf of Mexico is 3.2 miles due to the curvature of the earth.
- The 20 percent best visibility over the 1994-1998 period for the Chassahowitzka NWR was 18 dv or a visual range of 40 miles. A comparison of maximum SCCT project regional haze impacts during oil-firing with this actual background level results in a change in β_{ext} of 1.97 percent; well below perceptible levels.

In addition, the actual sulfur content of the fuel oil supplied to the Payne Creek Generating has been approximately 20 percent below the contract level of 0.05 weight percent. The actual sulfur content of future fuel oil deliveries are expected to be comparable to the historical values.

As noted in the air construction permit application, the use of ultra low sulfur distillate (ULSD) oil for the PCGS simple cycle combustion turbines results in a cost effectiveness of \$15,231 per ton of SO_2 reduced. This cost effectiveness is well above the level considered economically reasonable in prior Department BACT determinations. The use of cost effectiveness as the metric in determining whether a control technology has an adverse economic impact is consistent with guidance found in EPA's *New Source Review Workshop Manual* and long-standing agency BACT policy.

Our requested SO_2 BACT of 0.05 weight percent sulfur for backup distillate fuel oil is also consistent with the BACT limit recently approved by the Department for the City of Tallahassee's Arvah B. Hopkins Station simple cycle combustion turbine project. The Department's Technical Evaluation and Final BACT Determination Peaker for this project indicated that 0.05% sulfur oil and pipeline natural gas are accepted as BACT given the relatively low annual SO_2 potential emissions.

Your continued expeditious processing of the PCGS Peaker Project air construction permit application will be appreciated. Please contact Mr. Mike Roddy at (813) 963-0994, Ext. 1224 if any you have any questions or need any additional information.

Sincerely,

M.P. Opalinski

Michael P. Opalinski
Vice President of Technical Services

Attachments

cc: C. Holladay
B. Oven
J. Kissel, SWD
G. Worley, EPA
J. Bunyak, NPS

ATTACHMENT A

PRATT & WHITNEY SCR COSTS

Pratt & Whitney Power Systems, Inc.

80 Lamberton Road
Windsor, CT 06095
(860) 565-3339

Pratt & Whitney
A United Technologies Company

November 3, 2004

Mr. Trevor Pannell
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, FL 33688

Ref: Payne Creek Peaker Project
FDEP Request for Additional Information , File number 04903-003-AC;PSD-FL-344;PA 89-25, dated September 23, 2004.

Subject: This information should help you in answering the attached questions from the State of Florida DEP

Dear Trevor:

As requested, responses to the issues raised by the Florida Department of Environmental Protection (FDEP) in their September 24, 2004 correspondence to Seminole Electric Cooperative, Inc. pertinent to Pratt & Whitney are provided as follows:

Question I. 1)

The total Capital cost for the SCR is $ **12,013,000** for 10 simple cycle CT's. The incremental deduction of $ **765,500** for 10 simple cycle CT's is a correct assumption. However, this would only be applicable if the Order was placed by the end of the first quarter next year. Once we procure the stacks and CO catalyst for the CO system only, they are not interchangeable with the SCR/CO System. Therefore, If after the first quarter next year the total cost would be $ **12,013,000** for 10 simple cycle CT's.

Questions I. 2) a), b), c), and d)

The capital costs provided by Pratt & Whitney include freight and instrumentation but not include sales tax or installation costs. We estimate a total SCR installation cost of $10,500,000 for the 10 simple cycle CT's.

Question II. 1)

A copy of our Gas Turbine Liquid Distillate Fuel Requirements is attached. As shown on Table 1 of this document, the maximum recommended distillate fuel oil sulfur content is 1.3 weight percent.

Please contact me if any you have any questions or need any additional information.

Sincerely,

Mark S. Etre
Project Manager

Cc: 0302 Contract File

Attached: PWPS FR-1 Rev D, GAS TURBINE LIQUID DISTILLATE FUEL REQUIREMENTS

ATTACHMENT B

REVISED SCR BACT ECONOMIC ANALYSIS

Table 5-8. Capital Costs for SCR System (10 SCCTs)

Item	Dollars	EPA Factor
Direct Capital Cost		
Equipment Cost	11,227,500	EC
Sales tax	789,400	0.06 × EC
Instrumentation	0	Included in EC
Freight	0	Included in EC
Total Purchased Equipment Cost (PEC)	**$12,016,900**	
Installation Cost		
Foundations and supports	961,400	0.08 × PEC
Handling and erection	1,682,400	0.14 × PEC
Electrical	480,700	0.04 × PEC
Piping	240,300	0.02 × PEC
Insulation for ductwork	120,200	0.01 × PEC
Painting	120,200	0.01 × PEC
Total Installation Cost (TIC)	**$3,605,200**	
Total Direct Capital Costs (DCC)	**$15,622,100**	**PEC + TIC**
Indirect Installation Cost		
General Facilities	781,100	0.05 × DCC
Engineering & Home Office Fees	1,562,200	0.10 × DCC
Process Contingency	781,100	0.05 × DCC
Total Indirect Installation Cost (IIC)	**$3,124,400**	
Project Contingency (PC)	2,812,000	0.15 x (DCC + IIC)
Total Plant Cost (TPC)	**$21,558,500**	DCC + IIC + PC
Preproduction Cost (PPC)	431,200	0.02 × TPC
Initial Ammonia Inventory Cost	1,425	14 day supply
Total Capital Investment (TCI)	**$21,991,125**	TPC + PPC

Sources: ECT, 2004.
P&W, 2004

Table 5-9. Annual Operating Costs for SCR System (10 SCCTs)

Item	Dollars	EPA Factor
Direct Cost		
Maintenance labor and materials (ML&M)	329,867	0.015 × TCI
Catalyst replacement cost		
Replacement (materials and labor) (RC)	7,919,500	
Disposal	158,390	0.02 × RC
Total Catalyst Replacement Cost (CRC)	**$8,077,890**	
Future Worth Factor (FWF)	0.2620	7.0%, 3.5 yrs
Annualized Catalyst Cost (ACC)	**$2,116,300**	CRC × FWF
Energy Cost	300	OAQPS algorithm
Aqueous Ammonia (AA)	106,600	$444 / ton (dry basis)
Energy penalty (EP)		
Turbine backpressure	294,000	0.20 / inch delta P
Emission Fee Credit (EFC)	(9,000)	$25 / ton NO_x
Total Direct Costs (TDC)	**$2,837,467**	ML&M + ACC + EP
Indirect Cost		
Capital Recovery Factor (CRF)	0.1098	7.0%, 15 yrs
Capital recovery	2,414,500	CRF × TCI
Total Indirect Cost (TIC)	**$2,414,500**	
Total Annual Cost (TAC)	**$5,251,967**	**TDC + TIC**

Sources: ECT, 2004.
SECI, 2004

Table 5-10. Summary of NO_x BACT Analysis

	Emission Impacts			Economic Impacts				Energy Impacts	
	Environmental Impacts								
Control Option	Emission Rates lb/hr	tpy	Emission Installed Reduction (tpy)	Total Annualized Capital Cost ($)	Cost Effectiveness Cost ($/yr)	Increase Over Over Baseline ($/ton)	Toxic Baseline (MMBtu/yr)	Environmental Impact (Y/N)	Adverse Impact (Y/N)
SCR	71.7	89.6	358.4	21,991,125	5,251,967	14,654	28,662	Y	Y
Baseline	358.4	448.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Ten P&W FT8-3 SCCTs, 100-percent load for 2,000 hr/yr/CT gas-firing and 500 hr/yr/CT oil-firing.

Sources: ECT, 2004.
P&W, 2004
SECI, 2004.

ATTACHMENT C

PRATT & WHITNEY GAS TURBINE DISTILLATE FUEL REQUIREMENTS

Pratt & Whitney A United Technologies Company Pratt & Whitney Power Systems, Inc.	PWPS SPECIFICATION	FR-1	REV D	SHEET 1 OF 6
		ISSUED BY : P. Lavendier		DATE: 8/18/95
		REVISE BY : D. Tougas		DATE: 7/8/03
	RELEASED	REFERENCE :		REV:

GAS TURBINE LIQUID DISTILLATE FUEL REQUIREMENTS

GENERAL

This document provides the requirements and general guidelines for light and medium hydrocarbon liquid distillate fuels which can be burned satisfactorily in PWPS/P&W aeroderivative industrial gas turbines.

Industrial gas turbines are capable of burning a variety of liquid fuels providing they have appropriate fuel delivery, injection and combustion systems for each class of fuel. Distillate liquid fuels are complex hydrocarbon mixtures processed from a wide variety of basic crude oil stocks, and have a broad range of property values. In some cases, such as gasoline, the hydrocarbon fraction may undergo further processing and acquire additives or, as with naphtha, may be offered for use in the as-distilled form.

This document recognizes three general categories of distillate fuels as defined by ANSI/ASME B 133.7M which may be employed in properly configured PWPS/P&W gas turbines. Category a is No. 0-GT fuels such as light naphtha, gasoline, and JP-4/ Jet B fuels which are highly volatile and require special handling and fuel system design. Categories b and c are No. 1-GT and No. 2-GT such as light to medium kerosene and diesel fuels which can be burned in the standard gas turbine, providing all fuel properties specified in the following Table 1 are met. Fuel treatment or conditioning, including heating, may be necessary to satisfy these requirements. Residual, ash bearing fuels, and blends of distillate and residual fuels are not suitable for aeroderivative gas turbines.

Industrial fuels may be obtained from a large number of producers with a broad range of properties. Contamination in transport and deterioration in storage are common problems. Poor and contaminated fuels greatly affect the performance and durability of gas turbines. Therefore, it is imperative for the gas turbine user to install a proper fuel system design and institute an effective fuel quality management program to insure and maintain clean, high quality fuels.

GUIDELINES FOR EFFECTIVE FUEL QUALITY MANAGEMENT

The fuel management system should be designed and in place prior to the site start-up. The following considerations should be addressed:

1) The fuel type is generally chosen on the basis of cost and availability, however, the effects of fuel on gas turbine operation and life cycle economics should be considered. Normally, high viscosity fuels such as heavy diesel are less expensive initially, but usually impact engine life and increase overall life cycle costs. Some fuels can be made usable through treatment and/or conditioning, and the cost of these processes should be factored into the overall economics. Possible treatment processes are water wash, heating, filtration, and centrifuge or cyclone separation.
2) The transport path between the fuel producing location and the customer's unloading/ storage area should be analyzed for possible contamination potential. Dedicated transport containers are highly

recommended.

3) The fuel storage equipment should be properly designed and sized and should be free of any contaminating or corrosive materials. Fuel storage time versus tank capacity should be balanced. Sufficient time should be allowed for incoming fuel to settle. The fuel for the gas turbine should not be removed from the bottom of the tanks, so as to avoid picking up heavy bottom ends. Tanks should be regularly drained from the bottom to remove the sediment.

4) The on-site conditioning and treatment systems should clean the impurities from the fuel and maintain high quality as it forwards the fuel to the gas turbine. The design should consider the quantity, placement and filtration efficiency of the filters.

5) The requirement for fuel preheating, if necessary, should be considered. Preheating is required for viscosity enhancement of heavy fuels and wax removal from high cloud point (waxy) fuels.

6) Safety requirements should be considered in the initial design phase, particularly if the fuel is one of the highly volatile Category a type fuels.

7) Contaminants brought in with the incoming gas turbine airflow should be considered. Proper air filtration is required. It is the normal practice to subtract the incoming air contaminants from the allowable fuel contaminant limit through a formula given in Note 7 of Table 1.

The operators of PWPS/P&W equipment must comply with all aspects of this specification, and ensure compliance by regularly taking and analyzing liquid fuel samples. Contaminants not normally present in the fuel at the production site may be introduced as a result of contact with sea water, other fuels, or insufficiently cleaned equipment during the transportation, handling and storage phases. If the fuel arriving at the user location falls out of compliance with the specification, and can not be made compliant by treatment, then the fuel supplier should be contacted immediately for a corrective action. Even a short period of operation with fuel of excess contaminants (salts, trace metals, particulates, wax. etc.) could seriously impact the gas turbine life and performance.

To further insure high quality fuel and continuous compliance, a regular maintenance program must be adopted for all on-site fuel handling, storage, conditioning and treatment systems. Regular replacement of filter elements, periodic draining of water, removal of sediments from the tanks, lines and sumps, and replacement of treatment fluids, etc., should be planned for and implemented.

PWPS/P&W requests review of the customer's final overall fuel management system design. PWPS bulletin no. 97M01 entitled "Distillate Fuel System Recommendations" is available for further details on implementing a quality fuel system. Additional guidance can be obtained by contacting your PWPS/P&W Marketing representative.

GAS TURBINE LIQUID DISTILLATE FUEL REQUIREMENTS

RECOMMENDED DISTILLATE FUELS

The following liquid distillate fuels can be used in the gas turbine, if the fuel property requirements listed in Table 1 are met for the fuel delivered to the inlet of gas turbine.

Category a (No. 0-GT): Naphtha Fuels, Unleaded gasoline types, wide-cut fuels of the JP-4 (MIL-T-5624), and Jet B (ASTM D 1655) types - SEE NOTE 3

Category b (No. 1-GT): Kerosene or other distillates of the JP-5 (MIL-T-5624); Jet A and A-1 (ASTM D1655); No. 1-D diesel fuel (ASTM D975); No. 1 fuel oil (ASTM D 396); and No. 1 GT gas turbine fuel oil (ASTM D2880) types.

Category c (No. 2-GT): Distillates of the No. 2 diesel fuel (ASTM D975) No. 2 fuel oil (ASTM D 396), No. 2 GT gas turbine, and marine diesel (MIL-F-16884) types.

GAS TURBINE LIQUID DISTILLATE FUEL REQUIREMENTS

TABLE 1: GAS TURBINE LIQUID FUEL PROPERTY REQUIREMENTS

Property	Limit	NOTE(S)	Test Method (Note 1)
Viscosity - cSt: Max. (for category a, b, and c) Min. at 100 °F (37.8°C) (for category a) Min. at 100 °F (37.8°C) (for category b&c)	 6.0 max. for starting, 12.0 max. for operation 0.5 min. 1.0 min	 2 3	 ASTM D445 ASTM D445 ASTM D445
Combined Free Water and Sediment, vol. % Particle Contamination, mg/gal. Particle Size - microns (micrometer)	0.1 max. 10.0 max. 20 max	 4 13	ASTM D2709 ASTM D2276 or ASTM D5452
Hydrogen - % by weight	12.4 min	5	ASTM D1018
Metal Contaminants - ppm by wt. Vanadium (V) Sodium (Na) + Potassium (K) Calcium (Ca) Lead (Pb) Copper (Cu)	 0.2 max. 0.2 max. 2.0 max. 0.1 max. 0.02 max.	 6 & 7 6 & 7 6 & 7 6 & 7 6 & 7	ASTM D3605
Copper corrosion	No.1 max.	8	ASTM D130
Fuel Category a (only) Flash Point, °F (°C) Reid Vapor Pressure, psi or Vapor Pressure by Mini- method, psi	 To be reported 12.5 max. 12.5 max.	 9	 ASTM D93 ASTM D323 ASTM D5191
Fuel Category b and c (only) Flash Point, °F (°C) Cloud Point, °F (°C) Carbon Residue (on 10% bottoms), %	 100 °F (37.7°C) or local regulatory limit 25 °F (14°C) below GT inlet fuel temp. 0.25 max.	 10	 ASTM D93 ASTM D2500 ASTM D524
Sulfur, % by mass	1.3	11, 12	ASTM D4294
Ash, % by mass	0.005 max.		ASTM D482
Net Heating Value, Btu/lb (kcal/kg)	To be reported		ASTM D4809
Specific Gravity	To be reported		ASTM D1298

GAS TURBINE LIQUID DISTILLATE FUEL REQUIREMENTS

NOTES TO REQUIREMENTS (TABLE 1)

NOTE 1

The most recent revision of the ASTM test method should be used insofar as practicable. An equivalent test method may be used in lieu of ASTM test method, if approved by PWPS/P&W.

NOTE 2

Maximum fuel viscosity at gas turbine fuel pump inlet shall be 6.0 cSt for starting and 12.0 cSt during operation. Fuel may be heated, to a maximum of 160 deg F (71C), to meet this requirement.

NOTE 3

In order to operate FT8 with Category a fuels, such as naphtha, specially designed PWPS/P&W fuel system components are required.

NOTE 4

The fuel delivered to the inlet of the gas turbine is to have a sediment level less than 10 mg./gallon of fuel. However, for practical extended fuel filter life, the fuel should have lower sediment levels

NOTE 5

Minimum hydrogen percentage by weight is 12.4; however, for optimum combustion, higher hydrogen percentage is recommended.

NOTE 6

To achieve the level of sensitivity required for the detection of some of these metals, the furnace atomic absorption method may be necessary. Since some trace metals can have harmful effects on gas turbine operation, it is necessary to impose limitations. Higher levels of Table 1 metallic levels, even for short period, will increase the gas turbine maintenance costs.

NOTE 7

Limits of metal contaminants in Table 1 assume no contaminants in the inlet air or injected water. For operation with contaminants in the inlet air or injected water, the maximum allowable limit of any particular contaminant in the fuel must be reduced according to the following formula:

Af = Lf - [Cair X (air/fuel weight ratio)] - [Cwater X (water/fuel weight ratio)]

where,		
	Af	= Maximum allowable contaminant in the fuel, ppm by wt.
	Lf	= Contaminant Limit as called out in Table 1, for example 0.2 for (Na+K)
	Cair	= Contaminant in inlet air, ppm by wt.
	Cwater	= Contaminant in injection and/or evaporative cooling water, ppm by wt.

GAS TURBINE LIQUID DISTILLATE FUEL REQUIREMENTS

NOTE 8

Copper corrosion test conditions are 2 hours at 212 deg F (100 deg C).

NOTE 9

No flash point limitation is specified; however, local regulatory limits and safety regulations must be met.

NOTE 10

The cloud point shall be at least 25 degrees F below the anticipated gas turbine fuel inlet temperature. To meet this requirement, additional fuel heating, to a maximum of 160 degrees F (71C), may be needed.

NOTE 11

Sulfur content limits Below 1.3% WT. are imposed when:

a) The local regulatory limits of sulfur oxides exhaust emissions are exceeded; then the fuel sulfur content must be reduced until the local regulatory limits are satisfied. For instance, the USA EPA limits fuel Sulphur content to 0.8% for SO_2 emissions control, but local codes vary widely.
b) If exhaust heat recovery equipment is employed; then the equipment manufacturer's limit may apply.

NOTE 12

High sulfur fuels will impact hot section repair interval dependent on the amount of alkalai metals present. The combination of high sulfur and high alkalais must be avoided.

NOTE 13

Maximum particle size to be controlled by filtration with a β_{20} ratio of 200.

Pratt & Whitney A United Technologies Company Pratt & Whitney Power Systems, Inc.	PWPS SPECIFICATION	FR-1	REV D	SHEET 1A OF 1
		ISSUED BY : P. Lavendier		DATE: 8/28/95
		REVISE BY : D. Tougas		DATE: 7/8/03
	RELEASED	REFERENCE :		REV:

GAS TURBINE LIQUID DISTILLATE FUEL REQUIREMENTS

REV LET	SHEETS AFFECTED	SHEETS ADDED	DESCRIPTION	REV BY & DATE	APPVD & DATE
A	1-4		1) Added 1.7 cs lower limit of viscosity 2) Changed NA + K limit to 0.2 ppm 3) Added sulfur limit to 1.3% max. 4) Changed format to FrameMaker 5) Revised verbiage to put more stringent requirements for fuel management 6) Updated test procedures to current standard	P. Lavendier 8/18/95 EC#8352	
B			Completely re-written and updated to allow the use of Naptha Fuels, lower min viscosities. Max allowable fuel viscosities were changed to be based on actual operating temperatures, rather than a fixed temperature.	EC#9025 T. Fox/D. Dalal 2/11/98	
C	All		Updated Logo to new PWPS Logo. Updated all TPM references to PWPS references.	EC#9925 L. DiSalvo 7/23/01	
D	4 4 5 & 6		1) Changed Free Water to Combined Free water and sediment. changed limit to 0.1% max by volume. Changed Test Method to ASTM D2709. 2) Changed sediment to Particulate Contamination. Removed metric unit (mg/l) (2.7) from Limit. Changed test method to ASTM D2276 or D5452. 3) Added Note 13 to Particle size 4) Removed Test Method IP288. 5) Added Test Method ASTM 4809 to Net Heating Valve. 6) Made various typographical changes. Added Note 13 regarding filtering.	EC#10620 D. Tougas 7/8/03	

ATTACHMENT D

REVISED FDEP APPLICATION FOR PERMIT – LONG FORM PROFESSIONAL ENGINEER CERTIFICATION

SO_2 EMISSION RATES

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **14.7** lb/hour **4.6** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **Pratt & Whitney Data**	7. Emissions Method Code: **5**
8. Calculation of Emissions: **Hourly emission rate based on distillate fuel oil-firing at rated load and 78°F ambient temperature.** **Annual rate based on natural gas-firing at rated load and 50°F ambient temperature for 2,000 hrs/yr and oil-firing at rated load and 78°F ambient temperature for 500 hrs/yr.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **1.0 gr S / 100 scf natural gas**	4. Equivalent Allowable Emissions: **0.9** lb/hour **1.1** tons/year
5. Method of Compliance: **Fuel analysis per 40 CFR Part 75, Appendix D.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(5), F.A.C. (BACT)** **Allowable and equivalent allowable emissions are for natural gas-firing at rated load, 50°F ambient temperature, and 2,500 hr/yr operation.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.05 weight % sulfur fuel oil**	4. Equivalent Allowable Emissions: **14.7** lb/hour **3.7** tons/year
5. Method of Compliance: **Fuel analysis per 40 CFR Part 75, Appendix D.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(5), F.A.C. (BACT)** **Allowable and equivalent allowable emissions are for distillate fuel oil-firing at rated load, 78°F ambient temperature, and 500 hr/yr operation.**	

SEMINOLE ELECTRIC COOPERATIVE, INC.
PAYNE CREEK GENERATING STATION
PEAKER PROJECT

Professional Engineer Certification

Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, the information presented in the Seminole Electric Cooperative, Inc. (SECI) response to the Department's Request for Additional Information (RAI) dated September 23, 2004 concerning the Payne Creek Generating Station Peaker Project are true, accurate, and complete based on my review of material provided by SECI engineering and environmental staff; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this submittal are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of air pollutants not regulated for an emissions unit, based solely upon the materials, information and calculations provided with this certification.

Thomas W. Davis   11/10/04
Signature   Date

(seal)

* Certification is applicable to the Seminole Electric Cooperative, Inc. (SECI) response to the Department's Request for Additional Information (RAI) dated September 24, 2004 concerning the Payne Creek Generating Station Peaker Project.

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

September 23, 2004

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Michael Opalinski, VP Technical Services
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, FL 33688-2000

Re: Request for Additional Information
Payne Creek Generating Station
Peaker Project
File No. 0490340-003-AC; PSD-FL-344; PA 89-25

Dear Mr. Opalinski:

The Department is in receipt of your PSD application, however in order to continue processing the application, we will need the additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

I. BACT Determination for NO_X
Seminole has rejected SCR based upon a calculated cost effectiveness of $16,052 per ton of NO_X removed. A total equipment cost of $11,277,500 was estimated for the 10 simple cycle combustion turbines (five Swift Pacs). Based upon the submitted information, it appears that the basis for this estimate was a Pratt & Whitney price quote for a combined SCR/Oxidation Catalyst System at $12,013,000, less a deduct of $785,500 for removal of the CO catalyst. Given that the submittal incorporates the application and corresponding sunk cost of an Oxidation Catalyst System in order to comply with 40 CFR 63, Subpart YYYY (compliance with which has currently been stayed), it seems more appropriate to estimate the SCR cost as only the incremental cost of the SCR catalyst. Accordingly, the Department requests:

1) As a measure of the price of the Oxidation Catalyst System, Seminole obtain a price quote from Pratt & Whitney for the same SCR/Oxidation Catalyst System, but which specifically includes a deduct for the SCR catalyst (rather than the oxidation catalyst).
2) Written clarification from Pratt & Whitney as to whether any of these items are included (either completely or partially) within the $12,013,000 SCR/Oxidation Catalyst System price quote:
   a) Sales tax
   b) Freight
   c) Base instrumentation
   d) Installation costs (foundations, electrical, piping, insulation, etc.)
3) Since the calculated cost effectiveness includes annual catalyst replacement costs, the cost of the initial catalyst charge should be deducted from the provided "Equipment Cost".
4) Seminole consider obtaining one or more additional price quotes for combined SCR/Oxidation Catalyst systems, in order to ensure the competitiveness of the OEM quote.

In addition to reviewing Seminole's submittals, the applicant should be aware that the Department intends to internally estimate the cost effectiveness of SCR based upon all information at its disposal.

II. BACT Determination for SO_2
Seminole has rejected the use of 0.0015% sulfur oil based upon a calculated cost effectiveness of $15,231 per ton of SO_2 removed. This calculation appears to be based upon the forecasted annual incremental cost of 0.0015%

sulfur oil above 0.05% sulfur oil ($542,237) divided by the annual incremental tons of SO_2 generated (35.6 tons). The Department requests the following:

1) Please provide the CT manufacturer (Pratt & Whitney)'s worst case distillate oil specifications, particularly with regards to the maximum sulfur content.
2) Please provide the basis for the requested 500 hours of operation on distillate oil. Based upon the submitted data, it appears that approximately 300 hours per year (or 60% of the requested annual distillate oil throughput) would allow Seminole to avoid a BACT review for SO_2.
3) Please evaluate the cost effectiveness of using 0.0065% sulfur fuel (or similar), or more specifically a liquid fuel with sulfur content between 0.05% and 0.0015%. The Department notes that it recently permitted JEA Brandy Branch for the use of 0.0065% liquid fuel.
4) Please provide the Department with alternatives for reducing the maximum change in light extinction at the Chassahowitzka NWR below 5.0%. By way of example, potential solutions include limiting the daily hours of liquid fuel operation, limiting the daily throughput of liquid fuel consumed, or limiting the sulfur content of the liquid fuel.

The Department wishes to point out that although the data source cited by Seminole supports an average $0.054 per gallon of fuel incremental cost difference between 0.05% and 0.0015% sulfur oils, the estimated costs are $1.243 versus $1.297 per gallon, representing only slightly more than a 4% increase in fuel cost. Also, Seminole should be advised that in a recent Draft BACT Determination by the Department (FPL Turkey Point), the use of 0.0015% sulfur oil was considered as BACT.

Please note that EPA and NPS have been copied on your application, and should FDEP receive questions or comments from them, we will forward you a copy.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): "The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."

If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9519.

Sincerely,

Michael P. Halpin, P.E.
Michael P. Halpin, P.E.
DARM/BAR

Mike Roddy, SECI
Tom Davis, ECT
Jerry Kissel, SWD
Buck Oven, PPSO
Gregg Worley, EPA Region 4
John Bunyak, NPS

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Michael Opalinski
VP Technical Services
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33688-2000

COMPLETE THIS SECTION ON DELIVERY

A. Signature
x P. Henry
☐ Agent
☐ Addressee

B. Received by (Printed Name)
P. HENRY

C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7000 1670 0013 3110 2066

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1540

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7000 1670 0013 3110 2066

Postage	$	Postmark Here
Certified Fee		
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Sent To
Mr. Michael Opalinski, VP Tec. Services
Seminole Electric Cooperative, Inc.
Street, Apt. No.; or PO Box No.
16313 North Dale Mabry Highway
City, State, ZIP+4
Tampa, Florida 33688-2000

PS Form 3800, May 2000 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Michael Opalinski, VP
Technical Services
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33688-2000

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Julie Ludwig ☐ Agent ☐ Addressee

B. Received by (Printed Name) Julie Ludwig

C. Date of Delivery 9/29/04

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Transfer from service label)* 7000 1670 0013 3110 3193

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1540

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7000 1670 0013 3110 3193

Postage	$	Postmark Here
Certified Fee		
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Sent To Mr. Michael Opalinski, VP Tech. Services
Seminole Electric Cooperative, Inc.
Street, Apt. No., or PO Box No. 16313 North Dale Mabry Highway
City, State, ZIP+4 Tampa, Florida 33688-2000

PS Form 3800, May 2000 See Reverse for Instructions