Document	Date	Date Stmp
Power Plant Siting Act Process Diagram		
Faxed Copy of Division of Administrative Hearing IN RE: Florida Power & Light Company - BobWhite-Manatee 230kV DOAH Case #07-000105TL OGC Case No. 07-0026		1/16/2007
In Re: Seminole Electric Cooperative Seminole Generating Station Unit 3 OGC Case No. 06-0780 DOAH Case No. 06-0929EPP Order of Remand		4/6/2007
In the Matter of an Application for Permit by Seminole Electric Cooperative, Inc. FDEP Draft Permit No. PSD-FL-375 Project No. 1070025-005-AC Siting No. PA78-10A2 Request for Enlargement of Time		
Mike Halpin DEP Authorization to Incur Travel Expenses To attend the Seminole Generating Station Unit 3 Site Certification Hearing		1/8-11/07
Hopping Green & Sams envelope addressed to Mike Halpin		
State of Florida Division fo Administrative Hearings IN RE: Seminole Electric Cooperative Seminole Generating Station Unit 3 Case No. 06-0929EPP		1/9/2007
State of Florida Division of Administrative Hearings IN RE: Seminole Electric cooperative Seminole Generating Station Unit 3 OGC No. 06-0780 DOAH No. 06-0929EPP Dept of Environmental Protection's Motion in Limine referring to Jan. 4, 2007 document		
Seminole Notice of Hearing Cancelation- Cancellation of January 9, 2007 Site Certification Hearing on Seminole Electric Unit 3 Project PA78-10A2; DOAH Case No. 06-0929EPP	1/9/2007	
Letter from Sierra Club to Mike Halpin, Jeff Koerner and Trina Vielhauer (Via Electronic Mail) Commenst of Intent to Approve PSD Major Modification to Add Ne Unit 3 at Sminole Electic Cooperative, Inc.	10/9/2008	
Synapse Energy Economics, Inc.- Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value	9/20/2005	
Letter from Sierra Club to Mike Halpin, Jeff Koerner and Trina Vielhauer (Via Electronic Mail) Commenst of Intent to Approve PSD Major Modification to Add New Unit 3 at Sminole Electic Cooperative, Inc.	10/9/2008	
Letter to Mr. James Frauen Manager, Environmental Affairs Seminole Electric Coop, Inc for 1070025-004-AC PSD-FL-372 from Patty Adams	2/24/2006	
Letter to John Bunyak, Chief Policy, Planning & Permit Review Brance NPS-Air Quality Div. for 1070025-004-AC PSD-FL-372 from Patty Adams for Jeff Koerner	2/17/2006	
Letter to Gregg M. worley, Chief Air Permits Section U.S. EPA Region 4 for 1070025-004-AC PSD-FL-372 from Patty Adams for Jeff Koerner	2/17/2006	

Letter to Gregg M. worley, Chief Air Permits Section U.S. EPA Region 4 for 1070025-005-AC PSD-FL-375 from Patty Adams for Jeff Koerner	3/15/2006	
Letter to John Bunyak, Chief Policy, Planning & Permit Review Brance NPS-Air Quality Div. for 1070025-005-AC PSD-FL-375 from Patty Adams for Jeff Koerner	3/15/2006	
Letter to Mr. James R. Frauen, manager of Environmental Affairs Seminole Electric Coop. Re: Request for Addional Information Pollution Controls Upgrade Project Seminole Generating Station, Units 1 & 2 DEP File 1070025-004-AC	3/1/2006	
Memo & Draft Permit for Seminole Electic Coop. Pollution Contr Upgrades including CAIR/CAMR DEP File No. 1070025-004-AC	4/28/2006	

Walker, Elizabeth (AIR)

From: Walker, Elizabeth (AIR)
Sent: Friday, September 05, 2008 11:25 AM
To: 'jfrauen@seminole-electric.com'
Cc: 'sosbourn@golder.com'; 'kkosky@golder.com'; 'rmanning@hgslaw.com'; Kirts, Christopher; 'phillisfox@gmail.com'; 'kristin.Henry@sierraclub.org'; 'joanne.spalding@sierraclub.org'; 'catherine_collins@fws.gov'; 'gcavros@att.net'; Seiler, Ann; Halpin, Mike; Vielhauer, Trina; Koerner, Jeff
Subject: SEMINOLE GENERATING STATION; 1070025-005-AC/PSD-FL-375
Attachments: Seminole NOFP.pdf

Attached is the official Notice of Final Permit for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send". We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/1070025.005.AC.F_pdf.zip

Owner/Company Name: SEMINOLE ELECTRIC COOPERATIVE, INC.
Facility Name: SEMINOLE GENERATING STATION
Project Number: 1070025-005-AC/PSD-FL-375
Permit Status: FINAL
Permit Activity: CONSTRUCTION/SGS Unit 3
Facility County: PUTNAM

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/eproducts/apds/default.asp .

Permit project documents are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation at (850)488-0114.

Elizabeth Walker
Bureau of Air Regulation
Division of Air Resource Management (DARM)
(850)921-9505

Walker, Elizabeth (AIR)

From: Vielhauer, Trina
Sent: Monday, October 06, 2008 1:58 PM
To: Walker, Elizabeth (AIR)
Subject: FW: Notice of Appeal - Sierra Club, Inc. vs. DEP & Seminole Electric
Attachments: Notice of Appeal.pdf

Different appeal but same case. For our main files. Thanks!

From: Crandall, Lea
Sent: Friday, October 03, 2008 3:52 PM
To: Vielhauer, Trina; Gibson, Victoria
Subject: FW: Notice of Appeal - Sierra Club, Inc. vs. DEP & Seminole Electric

FYI! Please see the attached Notice of Appeal filed today.

Thanks,
Lea

Lea Crandall
Agency Clerk
Office of General Counsel
3900 Commonwealth Boulevard, MS 35
Tallahassee, FL 32399-3000
Phone: (850) 245-2212
Fax: (850) 245-2303

From: Crandall, Lea
Sent: Friday, October 03, 2008 3:50 PM
To: Beason, Tom; Morgan, Larry; Chisolm, Jack
Cc: Reardon, Bevin; Brown, Lisa L.
Subject: Notice of Appeal - Sierra Club, Inc. vs. DEP & Seminole Electric

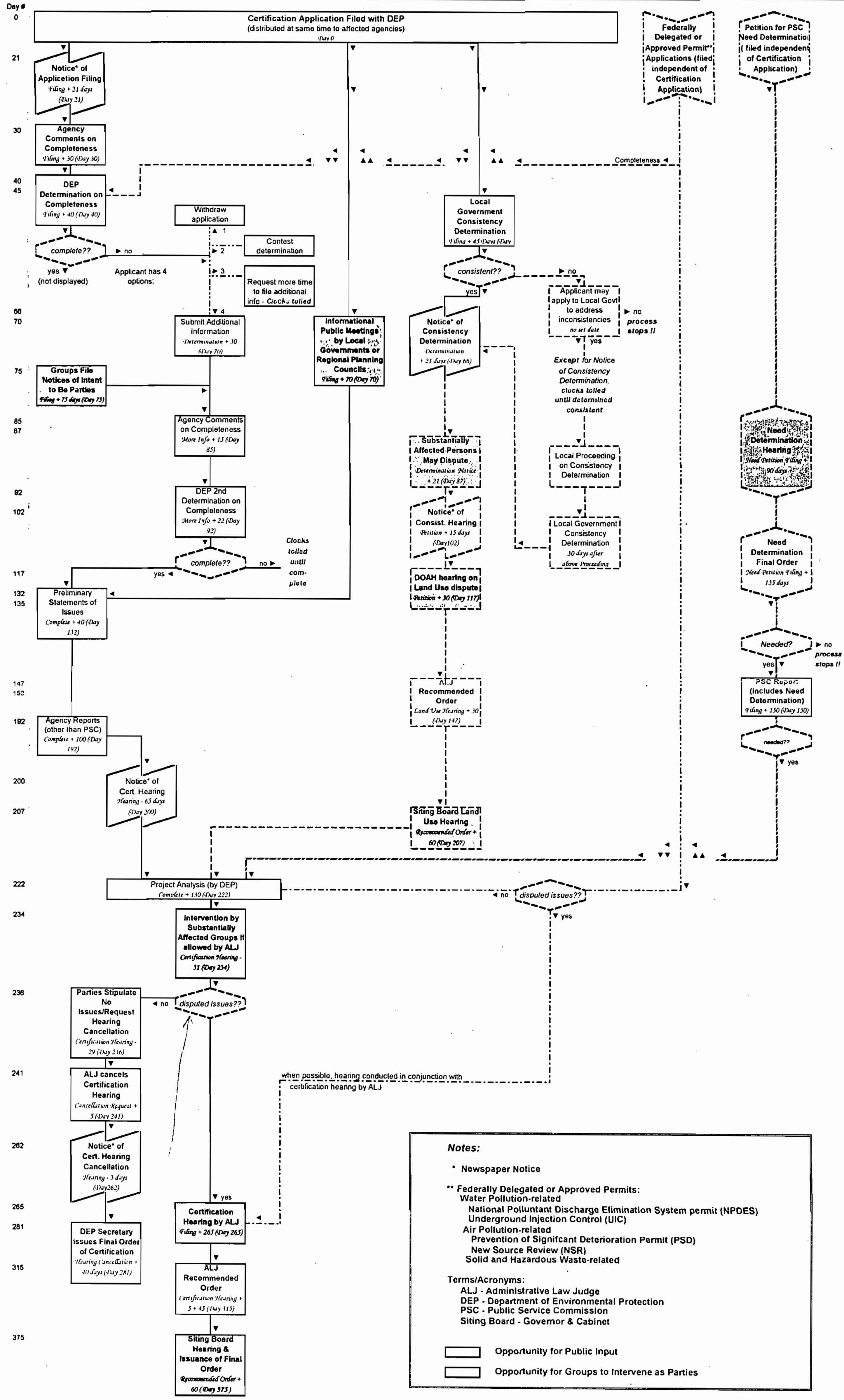
Please see the attached Notice of Appeal. I have also attached the Notice of Appeal Report Form.

Thanks,
Lea

Lea Crandall
Agency Clerk
Office of General Counsel
3900 Commonwealth Boulevard, MS 35
Tallahassee, FL 32399-3000
Phone: (850) 245-2212
Fax: (850) 245-2303

2

Power Plant Siting Act Process



M:\WP\CHARTS & STATISTICS\Flowcharts\PPSA Flowchart - full-15Feb07

STATE OF FLORIDA
DIVISION OF ADMINISTRATIVE HEARINGS

IN RE: FLORIDA POWER & LIGHT COMPANY
BOBWHITE – MANATEE 230 kV
TRANSMISSION LINE PROJECT
TRANSMISSION LINE SITING APPLICATION
NO. TA07-14

DOAH CASE NO. 07-000105TL
OGC CASE NO. 07-0026

______________________________/

DEPARTMENT OF ENVIRONMENTAL PROTECTION'S PROPOSED SITE CERTIFICATION APPLICATION SCHEDULE

Pursuant to §403.5251(2), Florida Statutes, the State of Florida Department of Environmental Protection files the attached Proposed Site Certification Application Schedule for this case, and asks that the Administrative Law Judge adopt the attached schedule.

Respectfully submitted this 16th day of January, 2007.

SCOTT A. GOORLAND
Senior Assistant General Counsel
Florida Bar No. 0066834

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION
Douglas Building, MS 35
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000
(850) 245-2242/ FAX 245-2302

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been sent by U.S. mail to the following listed persons this 16th day of January, 2007:

James V. Antista, General Counsel
Fish and Wildlife
Conservation Commission
620 South Meridian Street
Tallahassee, FL 32399-1600

Martha Carter Brown, Esquire
Florida Public Service Commission
Gerald Gunter Building
2450 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Sheauching Yu, Esquire
Department of Transportation
Haydon Burns Building
605 Suwannee Street, MS 58
Tallahassee, FL 32399-0450

Kelly Martinson, Esquire
Department of Community Affairs
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100

Liz Donley, Esquire
Southwest Florida Regional Planning
Council
1926 Victoria Avenue
Ft. Myers, FL 33901

Marti Moore, Esquire
Southwest Florida Water Management
District
2379 Broad Street
Brooksville, FL 34604

Carolyn Raepple
Hopping Green & Sams, P.A.
Post Office Box 6526
Tallahassee, FL 32314

Roger Tucker
Martin Shelby
Tampa Bay Regional Planning Council
4000 Gateway Centre Boulevard
Suite 100
Pinellas Park, FL 33782

Tedd N. Williams, Jr., Esquire
Manatee County Attorneys Office
Post Office Box 1000
Bradenton, FL 34206-1000

Stephen E. DeMarsh, Esquire
Sarasota County Attorneys Office
1660 Ringling Boulevard, 2nd Floor
Sarasota, FL 34236-6870

Robert Fournier, Esquire
City of Sarasota
1565 First Street
Sarasota, FL 34236

Brian Brattebo, Esquire
Florida Power & Light Company
Post Office Box 14000
Juno Beach, FL 33408

SCOTT A. GOORLAND
Senior Assistant General Counsel

DEPARTMENT OF ENVIRONMENTAL PROTECTION'S PROPOSED SCHEDULE FOR REVIEW OF SITE CERTIFICATION APPLICATION FLORIDA POWER AND LIGHT BOBWHITE-MANATEE 230 kV TRANSMISSION LINE PROJECT TRANSMISSION LINE SITING APPLICATION NO. TA 07-14 OGC CASE NO. 07-0026 DOAH CASE NO. 007-000105

January 2, 2007	Florida Power and Light ("FPL") files Site Certification Application ("SCA") for project with Department of Environmental Protection ("DEP") and all agencies.
January 9, 2007	DEP requests the appointment of an Administrative Law Judge (ALJ), files list of additional persons and agencies entitled to notice and copies of the application and amendments.
January 10, 2007	ALJ appointed.
January 17, 2007	DEP files proposed schedule of dates for processing of application.
January 23, 2007	DEP and FPL publish notice of the filing of the SCA.
February 1, 2007	Agencies' statements on completeness of the application due to DEP.
February 8, 2007	DEP issues initial determination on completeness. (Schedule assumes application is not complete at this point.)
February 21, 2007	Agencies issue preliminary statements of issues.
February 22, 2007	FPL to file response to DEP determination on completeness. FPL files additional information in response to DEP determination on completeness. (Schedule assumes FPL will file additional information.)
February 26, 2007	Deadline for holding of local government informational public meetings.
March 8, 2007	Agencies file second statements on completeness based on additional information submitted by FPL.
March 15, 2007	DEP issues second completeness determination. (Schedule assumes application complete at this point. If a determination of incompleteness is issued, then pursuant to Section 403.5066, F.S., all time frames are tolled until the application is determined complete.)
March 25, 2007	Deadline for DEP and FPL publish notice of the certification hearing before the administrative law judge.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In Re: SEMINOLE ELECTRIC COOPERATIVE SEMINOLE GENERATING STATION UNIT 3 POWER PLANT SITING APPLICATION NO. PA 78-10A2.	OGC CASE NO. 06-0780 DOAH CASE NO. 06-0929EPP

ORDER OF REMAND

On February 23, 2007, the Administrative Law Judge ("ALJ") assigned by the Division of Administrative Hearings ("DOAH"), issued an order closing file that granted the parties' request to cancel the certification hearing in accordance with Section 403.508(6), Florida Statutes. The order was issued pursuant to a Joint Stipulation Between The Parties filed on February 22, 2007. Therefore, under Section 403.509(1)(a), Florida Statutes, the Department of Environmental Protection ("DEP" or "Department") is required to prepare and enter a written order determining whether an application should be approved in accordance with the terms of the Florida Electrical Power Plant Siting Act ("PPSA") and the stipulation of the parties in requesting cancellation of the certification hearing. The matter is now before the Secretary of DEP for agency action.

STATEMENT OF THE ISSUE

The issue to be decided in this proceeding is whether DEP, acting in lieu of the Siting Board, should approve certification in accordance with the PPSA, Sections 403.501, et seq., Florida Statutes, authorizing Seminole Electric Cooperative, Inc., ("Seminole" or "Applicant") to construct and operate a new electrical generating unit at Seminole's existing

Seminole Generating Station site (consisting of existing Units 1 and 2) in an unincorporated area of Putnam County.

PRELIMINARY STATEMENT

On March 9, 2006, Seminole filed a Site Certification Application ("SCA") to construct and operate a new electrical power plant unit ("Unit 3") at the existing Seminole Generating Station ("SGS") site in Putnam County, Florida. The existing site, which presently includes Units 1 and 2 and directly associated facilities, is located approximately five miles north of the city of Palatka.

The Department determined that Seminole's SCA was complete on March 24, 2006. DEP then issued a Notice of Insufficiency on May 15, 2006. Seminole filed its Response to the Department's Notice of Insufficiency on May 30, 2006, and then submitted a Response to Sufficiency Request for Information on June 30, 2006. On July 26, 2006, the Department determined that Seminole's SCA was sufficient.

Pursuant to Section 403.507, Florida Statutes, several reviewing agencies submitted agency reports and proposed Conditions of Certification on Seminole's Unit 3 SCA. On November 9, 2006, the Department issued its Staff Analysis Report ("SAR"), incorporating the reports and recommendations of the reviewing agencies. In the SAR, the Department recommended certification of the proposed Seminole Generating Station Unit 3, subject to a comprehensive set of Conditions of Certification.

On June 1, 2006, a land use hearing was held for the purposes of determining whether Seminole's Unit 3 project was consistent and in compliance with local land use plans and zoning ordinances of Putnam County. On August 31, 2006, the assigned ALJ entered a Recommended Order, which concluded that the Unit 3 project and site were consistent and in compliance with Putnam County's land use plans and zoning ordinances. On December 5, 2006, the Siting Board unanimously approved a Final Order adopting the land use Recommended Order, and finding that the Unit 3 project was consistent and in compliance with applicable land use plans and zoning ordinances. The Siting Board's Final Order on Land Use was signed by the Governor and issued on December 8, 2006.

Public notice of the filing of the Site Certification Application was published by the Applicant in the Palatka Daily News on April 7, 2006, and by the Department on April 7, 2006, in the Florida Administrative Weekly ("FAW"). Pursuant to Section 403.5115(1)(e), Florida Statutes, notice of the certification hearing originally scheduled to begin on January 9, 2007, was published in the Palatka Daily News on November 25, 2006, and by the Department in the FAW on November 22, 2006. By Order of the ALJ dated January 8, 2007, the certification hearing was rescheduled to March 15, 2007. That notice was published in the Palatka Daily News on January 18, 2007.

On February 22, 2007, the Applicant, DEP, the Department of Community Affairs, the Department of Transportation, the Sierra Club, and the St. Johns River Water Management District filed a Joint Stipulation addressing certification issues. In the Joint Stipulation, all parties stipulated that they do not object to certification of Seminole's Unit 3 project subject to the Conditions of Certification included in the SAR.

The Joint Stipulation of February 22, 2007, also stipulated pursuant to Section 403.508(6)(a), Florida Statutes, that there are no disputed issues of fact or law to be raised at the certification hearing and requested that the ALJ relinquish jurisdiction. Sufficient time remained to publish public notices of the cancellation of the hearing at least three days prior to the scheduled hearing date, as required under Section 403.508(6)(a), Florida Statutes.

The ALJ timely issued an order closing file on February 23, 2007, granting the parties' request to cancel the certification hearing. DEP published notice of cancellation of the certification hearing in the FAW on March 9, 2007. The Applicant published a similar notice on March 10, 2007, in the Palatka Daily News.

AUTHORITY FOR REMAND

The authority of a state agency to remand an administrative case back to DOAH for further proceedings where additional findings of fact and related conclusions of law are critical to the issuance of a coherent final order is well established by the controlling case law of Florida. See, e.g., Dept. of Environmental Protection v. Dept. of Management Services, Div. of Adm. Hearings, 667 So.2d 369 (Fla. 1st DCA 1995); Collier Development Corp. v. State, Dept. of Environmental Regulation, 592 So.2d 1107 (Fla. 2d DCA 1991); Dept. of Professional Regulation v. Wise, 575 So.2d 713 (Fla. 1st DCA 1991); Manasota 88, Inc. v. Tremor, 545 So.2d 439 (Fla. 2d DCA 1989); Miller v. State, Dept. of Environmental Regulation, 504 So.2d 1325 (Fla. 1st DCA 1987); Cohn v. Dept. of Professional Regulation, 477 So.2d 1039, 1047 (Fla. 3d DCA 1985).

NECESSITY FOR REMAND

It is normally the duty of the ALJ to make basic findings of fact in a formal proceeding where agency action is being formulated. See, e.g., Putnam County Environmental Council v. Georgia Pacific Corp., 24 FALR 4674, 4685 (Fla. DEP 2002); Miccosukee Tribe of Indians v. South Florida Water Management District, 20 FALR 4482, 4491 (Fla. DEP 1998), *aff'd*, 721 So.2d 389 (Fla. 3d DCA 1998); Barrininger v. Speer and Associates, 14 FALR 3660, 3667 n.8 (Fla. DER 1992); see also Save Anna Maria, Inc. v. Dept. of Transportation, 700 So.2d 113, 116 (Fla. 2d DCA 1997); 1800 Atlantic Developers v. Dept. of Environmental

Regulation, 552 So.2d 946, 955 (Fla. 1st DCA 1989), *rev. denied*, 562 So.2d 345 (Fla. 1990).

In PPSA cases Section 403.508(6)(a), Florida Statutes, permits the parties to request that the certification hearing be cancelled and the matter remanded to the Department when the parties stipulate that there are no disputed issues of fact or law to be raised at the certification hearing. If such a remand occurs, Section 403.509(1)(a), Florida Statutes, requires the Secretary to "act upon the application by written order in accordance with the terms of this act and the stipulation of the parties in requesting cancellation of the certification hearing." The PPSA requires that the Secretary consider how the location, construction, and operation of the proposed project will:

> (e) Effect a reasonable balance between the need for the facility as established pursuant to s. 403.519 and the impacts upon air and water quality, fish and wildlife, water resources, and other natural resources of the state resulting from the construction and operation of the facility.
>
> (f) Minimize, through the use of reasonable and available methods, the adverse effects on human health, the environment, and the ecology of the land and its wildlife and the ecology of state waters and their aquatic life.
>
> (g) Serve and protect the broad interests of the public.

The Joint Stipulation merely stipulated that there were no disputed issues of fact to be raised at the certification hearing. However, the Joint Stipulation did not contain specific findings of fact that would allow me to fulfill my obligations to consider and balance the factors listed above. It is therefore necessary to remand this matter to DOAH for the purpose of further developing a factual record through either further administrative proceedings or submittal of a stipulation that provides detailed facts addressing the factors set forth above.

It is therefore ORDERED:

This proceeding is remanded to DOAH for the purpose of developing a factual record through either further administrative proceedings or submittal of a stipulation that provides detailed facts addressing the factors set forth above.

Any party to this proceeding has the right to seek judicial review of the Final Order pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, M.S. 35, Tallahassee, Florida 32399-3000; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Final Order is filed with the clerk of the Department.

DONE AND ORDERED this 4th day of April, 2007, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

MICHAEL W. SOLE
Secretary

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

FILED ON THIS DATE PURSUANT TO § 120.52, FLORIDA STATUTES, WITH THE DESIGNATED DEPARTMENT CLERK, RECEIPT OF WHICH IS HEREBY ACKNOWLEDGED.

Syndie Kinsey — CLERK 4-4-07 — DATE

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing Order of Remand has been sent by United States Postal Service to:

James V. Antista, Esq.
Fish and Wildlife Conservation Commission
620 South Meridian Street
Tallahassee, FL 32399-1600

Kelly A. Martinson, Esq.
Department of Community Affairs
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100

Sheauching Yu, Esq.
Department of Transportation
Haydon Burns Building
605 Suwannee Street, MS 58
Tallahassee, FL 32399-0450

Martha Carter Brown, Esq.
Florida Public Service Commission
Gerald Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Gordon B. Johnston, Esq.
County Attorney
601 Southeast 25th Avenue
Ocala, FL 34471

Mark Scruby, Esq.
Clay County Attorney
Post Office Box 1366
Green Cove Springs, FL 32043

Vance W. Kidder, Esq.
St. Johns River Water Management District
4049 Reid Street
Palatka, FL 32177

Brian Teeple
Northeast Florida Regional Planning Council
6850 Belfort Oaks Place
Jacksonville, FL 32216

Russell D. Castleberry, Esq.
Post Office Box 758
Palatka, FL 32178

Patrick Gilligan
Attorney for City of Ocala
1531 SE 36 Avenue
Ocala, FL 34471

Wayne Smith
Union County Board of County Comm.
15 Northeast First Street
Lake Butler, FL 32054

Ronald Williams
Columbia County Board of County Comm.
Post Office Drawer 1529
Lake City, FL 32058

Timothy Keyser, Esq.
Sierra Club
Post Office Box 62
Interlachen, FL 32148-0092

James S. Alves, Esq.
Douglas S. Roberts, Esq.
Hopping Green & Sams
Post Office Box 6526
Tallahassee, FL 32314

and by hand delivery to:

Scott Goorland, Esquire
Department of Environmental Protection
3900 Commonwealth Blvd., M.S. 35
Tallahassee, FL 32399-3000

Michael P. Halpin
Office of Siting Coordination
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

this 5th day of April, 2007.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

FRANCINE M. FFOLKES
Senior Assistant General Counsel

3900 Commonwealth Blvd., M.S. 35
Tallahassee, FL 32399-3000
Telephone 850/245-2242

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of an
Application for Permit by:

FDEP Draft Permit No.: PSD-FL-375
Project No.: 1070025-005-AC
Siting No. PA78-10A2

Seminole Electric Cooperative, Inc.
Seminole Power Plant
Putnam County, Florida
_______________________________________/

REQUEST FOR ENLARGEMENT OF TIME

By and through undersigned counsel, Seminole Electric Cooperative, Inc., (Seminole Electric) hereby requests, pursuant to Florida Administrative Code Rule 62-110.106(4), an enlargement of time, to and including October 23, 2006, in which to file a Petition for Administrative Proceedings in the above-styled matter. As good cause for granting this request, Seminole Electric states the following:

1. On or about August 28, 2006, Seminole Electric Cooperative, Inc. (Seminole) received from the Department of Environmental Protection ("Department") an "Intent to Issue Air Permit" and accompanying "Draft Permit," (Draft Permit No.1070025-005-AC), to add a new Unit 3 at the Seminole Generating Station, located in Putnum County, Florida.

2. Based on Seminole's initial review, the Draft Permit and associated documents contain several provisions that warrant clarification or corrections. Seminole will be filing comments shortly and meeting with the Department to work towards a resolution.

3. This request is filed simply as a protective measure to avoid waiver of Seminole's right to challenge certain conditions contained in the Draft Air Permit. Grant of this request will not prejudice either party, but will further their mutual interest and hopefully avoid the need to file a Petition and proceed to a formal administrative hearing. Seminole will promptly withdraw this request after its comments are resolved, and the 30-day public comment period is passed.

WHEREFORE, Seminole Electric Cooperative, Inc. respectfully requests that the time for filing of a Petition for Administrative Proceedings in regard to the Department's Intent to Issue Air Permit No.1070025-005-AC be formally extended to and including October 23, 2006.

RESPECTFULLY SUBMITTED this 11 day of September, 2006.

By: Robert Manning

Robert A. Manning
Florida Bar ID No. 0035173
Hopping Green & Sams, P.A.
123 South Calhoun Street
Post Office Box 6526
Tallahassee, Florida 32314
(850) 222-7500
(850) 224-8551 Facsimile

Attorneys for Seminole Electric Cooperative, Inc.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by Hand Delivery to Leigh Crandell, Agency Clerk, and Doug Beason, General Counsel, Florida Department of Environmental Protection, 3900 Commonwealth Boulevard, Room 659, Tallahassee, Florida 32399-3000; and Mike Halpin, Florida Department of Environmental Protection, Program Administrator, 2600 Blair Stone Road, Room 625, Tallahassee, Florida 32399, this 11 day of September, 2006.

Robert Manning

Robert A. Manning

#248295

COPY

DEP Authorization to Incur Travel Expenses

Traveler:	Michael P. Halpin	**Phone#:**	245-8007
SSN:	300-50-6750	**HQ:**	Tallahassee
Div/Bur:	Energy / Siting	**Preparer:**	Landa F. Korokous
Org:	37 570401000 **EO:** AD	**Module:**	8020B
Grant:	0 **Project:** 0	**08/14 Cat/Yr:**	0

	Cost Estimate
Meals:	$102.00
Per Diem:	$80.00
Lodging:	$300.00
Airfare:	
Car Rental:	
Registration Fees:	
Other Expenses:	$160.00
Total:	$642.00

☐ Reg Fees Paid Directly to Vendor
☐ Reg Fees Paid By Employee

Dates: January 8, 2007 **To** January 11, 2007

Destination: Palatka, FL

Purpose: To attend the Seminole Generating Station Unit 3 Site Certifiacation Hearing

Benefits to State: 0

Comments: Permission to drive personal vehicle

Traveler's Signature: Michael P. Halpin

Title: Program Administrator **Date:**

Pursuant to Section 112.061, Florida Statutes, I hereby certify or affirm that the above anticipated travel will be on official business of the State of Florida.

Supervisor Signature:

Title: Director **Date:** 1/5/07

Authorizing Signature:

Title: Director **Date:**

Additional Authorizing Signature:
If additional approval is required by division/district/office policy.

Title: 0 **Date:**

Hopping Green & Sams
Attorneys and Counselors

Post Office Box 6526
Tallahassee, Florida 32314

Mike Halpin
Florida Dept. of Environmental Protection
2600 Blair Stone Road, Room 625
Tallahassee, FL 32399

STATE OF FLORIDA
DIVISION OF ADMINISTRATIVE HEARINGS

IN RE: SEMINOLE ELECTRIC COOPERATIVE SEMINOLE GENERATING STATION UNIT 3 POWER PLANT SITING APPLICATION NUMBER PA 78-10A2	Case No. 06-0929EPP

ORDER GRANTING CONTINUANCE AND RE-SCHEDULING HEARING

This cause having come before the undersigned on the Joint Motion of FDEP, Seminole Electric Cooperative and Sierra Club for Continuance to Allow Time for Cancellation of Site Certification Hearing (Continuance Motion), filed January 8, 2007, and the undersigned being fully advised, it is, therefore,

ORDERED that:

1. The Continuance Motion is hereby granted, and the final hearing in this cause scheduled for January 9 through 12, 2007, is hereby canceled.

2. This cause is hereby re-scheduled for final hearing on March 15, 2007, at 9:00 a.m., at a location in Palatka, Florida, to be determined and noticed at a later date.

3. Except as modified herein, all other provisions of the first Notice of Hearing and of the Order of Pre-hearing Instructions shall remain in full force and effect.

4. All subpoenas previously issued and served shall remain in full force and effect for the re-scheduled hearing date as to any witness who is provided with a copy of this Order.

DONE AND ORDERED this 8th day of January, 2007, in Tallahassee, Leon County, Florida.

J. LAWRENCE JOHNSTON
Administrative Law Judge
Division of Administrative Hearings
The DeSoto Building
1230 Apalachee Parkway
Tallahassee, Florida 32399-3060
(850) 488-9675 SUNCOM 278-9675
Fax Filing (850) 921-6847
www.doah.state.fl.us

Filed with the Clerk of the
Division of Administrative Hearings
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STATE OF FLORIDA
DIVISION OF ADMINISTRATIVE HEARINGS

IN RE: SEMINOLE ELECTRIC COOPERATIVE
SEMINOLE GENERATING STATION
UNIT 3
POWER PLANT SITING APPLICATION
NUMBER PA 78-10A2

OGC NO. 06-0780
DOAH NO. 06-0929EPP

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DEPARTMENT OF ENVIRONMENTAL PROTECTION'S MOTION IN LIMINE

The Florida Department of Environmental Protection ("Department"), by and through its undersigned counsel, and pursuant to Rule 28-106.204, Florida Administrative Code, moves to exclude or alternatively to limit the testimony and evidence set forth below, and in support thereof states:

1. This is a proceeding under the Florida Electrical Power Plant Siting Act, Section 403.508 – 403.518, Florida Statutes (2005), arising from an application from Seminole Electric Cooperative ("Applicant") for site certification of the Seminole Generating Station Unit 3.

2. In the Prehearing Stipulation filed on January 4, 2007, the Sierra Club indicated it's intent to raise the following as disputed issues of facts or law in this proceeding:

a. Whether Seminole conducted an adequate BACT analysis for CO, VOC, PM, PM_{10} and mercury.

b. Whether the emission reductions for mercury is accurately quantified and guaranteed.

c. Whether there should be a PSD review for mercury.

d. Whether Seminole's baseline actual emissions data is correctly reported and stated.

e. Whether the proposed testing requirements are adequate to ensure enforceability.

f. Whether the proposed project complies with the law.

g. Whether the proposed permit can exempt emissions from start-up, shutdown or malfunction from BACT limits.

h. Whether Seminole adequately considered reasonable alternatives to its proposed Unit 3.

3. The Department specifically objects to the relevance and propriety in this proceeding of Sierra Club's issues stated above in paragraphs 2.a., 2.b., 2.c., 2.d., and 2.g. in that they are issues reserved for the Department's separately issued PSD permit under the Department's separate authority under its New Source Review program, which is not a subject of this proceeding. Additionally, the Department objects to the relevance and propriety in this proceeding of Sierra Club's issues stated above in paragraphs 2.e., 2.f., and 2.h. in any manner intended to refer to issues reserved to the Department under the Department's separate PSD permit under the New Source Review program.

4. Any evidence or testimony related to these issues must be excluded from this proceeding.

<u>The Siting Board may only consider evidence relevant to their appropriate authority provided by the Power Plant Siting Act</u>

5. Under S. 403.509, F.S. (2005), the agency taking final action on the certification of Seminole Unit 3 is the Siting Board.

6. Pursuant to Section 403.502, F.S. (2005), and Rule 62-17.141(1), F.A.C., the certification hearing and recommended order issued thereupon shall address the extent to which:

- The certification ensures, through available and reasonable methods that the location and operation of the electrical power plant will produce minimal adverse effects on human health, the environment, the ecology of the land and its wildlife, and the ecology of state waters and their aquatic life and will not unduly conflict with the goals established by the applicable local comprehensive plans.

- The certification will fully balance the increasing demands for electrical power plant location and operation with the broad interests of the public.
- The certification will assure the citizens of Florida that operation safeguards are technically sufficient for their welfare and protection.
- The certification will effect a reasonable balance between the need for the facility and the environmental impact resulting from construction and operation of the facility, including air and water quality, fish and wildlife, and the water resources and other natural resources of the state.

7. S. 403.509(2), F.S. (2005), states, "The issues that may be raised in any hearing before the [siting] board shall be limited to those matters raised in the certification proceeding before the administrative law judge or raised in the recommended order."

8. Thus, in considering the final order on certification, the Siting Board may only consider evidence related to the purposes stated above in paragraph 6.

Issues of fact or law solely relevant to the proceeding for the issuance of the Prevention of Significant Deterioration permit under the Department's New Source Review program must be excluded from this proceeding

9. Pursuant to S. 403.061(35), F.S., the Department of Environmental Protection is the agency that has been granted the sole authority to "Exercise the duties, powers, and responsibilities required of the state under the federal Clean Air Act, 42 U.S.C. ss. 7401 et seq." As part of the Clean Air Act, the Department administers the New Source Review Program, which includes the issuance of PSD Permits. (See 42 U.S.C. s. 7410, 7471-74-79; 40 CFR s. 51.160-51.165; 40 CFR Part 52 Subpart K) The Siting Board has not been granted the authority to make determinations under these provisions related to the New Source Review Program. (See 40 CFR 52.530: See also 57 FR 54931, Attachment "A")

10. The only time that issues proper for consideration under the New Source Review or PSD programs can be considered at a certification hearing is when a related PSD draft permit has been timely challenged under the provisions of the PSD program. S. 403.507(3), F.S. (2005), provides, "If a petition for an administrative hearing on the department's preliminary determination is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing." In such an instance, the PPSA makes it clear that the record of the certification hearing must be considered by the Department of Environmental Protection in issuance of the PSD permit (see, e.g., 403.508(3), F.S, (2005)). However, as noted, under S. 403.507(3), F.S. (2005), that is *only* when a petition is filed on department's preliminary determination on the PSD permit action. Even in such an instance, the Siting Board may not consider issues left to the Department for issuance of the PSD permit. In such an instance where a petition has been received by the Department on a PSD permit, and the hearing has been consolidated, S. 403.509(3), F.S. (2005), makes it clear that it is the *Department* that is to consider these issues in issuing the PSD permit, not the Siting Board. S. 403.509(3), F.S. (2005), states, in pertinent part:

> "The *department's* actions on a federally required new source review or prevention of significant deterioration permit shall be based on the record and recommended order of the certification hearing and of any other proceeding held in connection with the application for a new source review or prevention of significant deterioration permit, on timely public comments received with respect to the application or preliminary determination for such permit, and on the provisions of the state implementation plan. The department's action on a federally required new source review or prevention of significant deterioration permit shall differ from the actions taken by the siting board regarding the certification if the federally approved state implementation plan requires such a different action to be taken by the department. *Nothing in this part shall be construed to displace the department's authority as the final permitting entity under the federally approved permit program.* Nothing in this part shall be construed to authorize the issuance of a new source review or prevention of significant deterioration permit which does not conform to the requirements of the federally approved state implementation plan." (emphasis added)

However, where no petition has been filed on the Department's preliminary determination on the PSD permit, then pursuant 403.507(3), F.S. (2005), there is no consolidation of issues at the certification hearing. In such an instance, pursuant to Section.403.061(35), F.S.; Section 403.509(3), F.S. (2005) ("Nothing in this part shall be construed to displace the department's authority as the final permitting entity under the federally approved permit program"); and Section 403.502, F.S. (2005), and Rule 62-17.141(1), F.A.C. (which provide what the certification hearing, the recommended order, and the Siting Board may address), issues within the exclusive authority of the Department to consider under the PSD program may not be raised at the certification hearing.

11. In addition to applying for certification under the PPSA, on March 9, 2006, Seminole applied to the Department for a PSD permit for the proposed Unit 3 Project.

12. The Department issued a proposed PSD permit issued on August 24, 2006 for the proposed Unit 3 project. (See Attachment "B") Included in that proposed permit, the Department determined BACT for specified air pollutants for the proposed Unit 3 project. The Department determined that the proposed Unit 3 project meets BACT requirements for purposes of the PSD permit, and also determined that the Unit 3 Project would not cause or contribute to violations of National and State Ambient Air Quality Standards.

13. In conjunction with issuance of the draft PSD permit, the Department provided a point of entry under Chapter 120, Florida Statutes, to persons whose substantial interests would be affected by the issuance of a PSD permit for the Unit 3 project.

14. The deadline for the filing of a petition on the draft PSD permit was September 22, 2006. No petition on the draft permit was timely received by the Department.

15. On October 16, 2006, the Department received Sierra Club's Motion for Enlargement of Time and Petition for Administrative Hearing from the Sierra Club on the draft PSD permit. (See Attachment "C")

16. On October 31, 2006, the Department issued an Order Dismissing Petition With Leave to Amend, denying Sierra Club's October 16, 2006 Motion for Enlargement of Time to challenge the draft PSD permit, and dismissing Sierra Club's Petition with leave to file an amended petition. (See Attachment "D")

17. The Sierra Club did not file an amended petition.

18. Therefore, no persons, including the Sierra Club, properly initiated Chapter 120, Florida Statutes proceedings contesting the Department's proposed agency action on the Unit 3 PSD permit.

19. Accordingly, the Department's final action of the PSD permit for Unit 3 cannot be contested in this proceeding.

WHEREFORE, the Department respectfully requests that the Administrative Law Judge exclude from this proceeding all evidence and testimony concerning issues within the exclusive authority of the Department under its separate New Source Review Program, including but not limited to issues such as the adequacy and propriety of BACT and other PSD determinations, the accuracy and adequacy of information and data for the purpose of making PSD determinations, the propriety of testing requirements in and for the PSD permit, whether the proposed project complies with PSD and New Source Review requirements, whether exemptions in the proposed PSD permit are proper under the relevant law, whether any project alternatives considered or not considered were proper for PSD permit purposes, and the

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been sent by U.S. Mail to the following listed persons this ___ day of January, 2007:

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____

propriety and legality of issuance of the PSD permit for Seminole Unit 3, and provide the Department such further relief as may be appropriate.

Respectfully submitted this ___ day of January, 2007.

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Senior Assistant General Counsel

CANCELLATION OF JANUARY 9 2007 SITE CERTIFICATION HEARING ON SEMINOLE ELECTRIC UNIT 3 PROJECT PA78-10A2; DOAH CASE NO. 06-0929EPP

The Site Certification Hearing on Seminole Electric Cooperative's Unit 3 electrical generating project will not be held as previously scheduled. The hearing was scheduled to begin at 9AM on Tuesday January 9, 2007 at the Campbell Civic Center at the Ravines Garden State Park in Palatka, Florida. ~~The hearing will not occur at that time.~~

The hearing was being held under the Florida Electrical Power Plant Siting Act, Chapter 403, Part II, Florida Statutes. However, the parties to the hearing have resolved the disputed issues ~~and have agreed that a formal hearing is no longer necessary.~~

At the request of the parties, state Administrative Law Judge J. Lawrence Johnston has tentatively rescheduled the H~~h~~earing for a later date. ~~Based on the resolution of the disputed issues among the parties, it is anticipated that the rescheduled hearing will be cancelled following formal public notice.~~ Accordingly, the Hearing is postponed until further notice.

The new Unit 3 is a 750 megawatt electrical generating unit to be located at the existing Seminole Electric Cooperative Generating Station located north of Palatka. That site already contains two similar electrical generating units.

Any person wishing to obtain information on this Project should contact either:

Jim Frauen Seminole Electric Cooperative, Inc. 16313 North Dale Mabry Highway Tampa, FL 33688 813-963-0994	Hamilton S. Oven, P.E. Florida Department of Environmental Protection Office of Siting Coordination 2600 Blair Stone Road Tallahassee, Florida 32399-2400 (850) 245-8006

Synapse
Energy Economics, Inc.

Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value

Prepared by:
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Revision 2
September 20, 2005

Executive Summary

The earth's climate is determined by concentrations of greenhouse gases in the atmosphere. International scientific consensus, expressed in the Third Assessment Report of the Intergovernmental Panel on Climate Change, is that climate will change due to anthropogenic emissions of greenhouse gases. Projected changes include temperature increases, changes in precipitation patterns, increased climate variability, melting of glaciers, ice shelves and permafrost, and rising sea levels. These changes have already been observed and documented in a growing body of scientific evidence. All countries will experience social and economic consequences, with disproportionate negative impacts on countries least able to adapt.

The prospect of Global Warming and changing climate has spurred international efforts to work towards a sustainable level of greenhouse gas emissions. These international efforts are embodied in the United Nations Framework Convention on Climate Change. The Kyoto Protocol, a supplement to the UNFCCC, establishes legally binding limits on the greenhouse gas emissions of industrialized nations and economies in transition.

Despite being the single largest contributor to global emissions of greenhouse gases, the United States remains one of a very few industrialized nations that have not signed the Kyoto Protocol. Nevertheless, individual states, regional groups of states, shareholders and corporations are making serious efforts and taking significant steps towards reducing greenhouse gas emissions in the United States. Efforts to pass federal legislation addressing carbon, though not yet successful, have gained ground in recent years. These developments, combined with the growing scientific understanding of, and evidence of, climate change, mean that establishing federal policy requiring greenhouse gas emission reductions is just a matter of time.

In this scientific and policy context, it is imprudent for decision-makers in the electric sector to ignore the cost of future carbon emissions reductions or to treat future carbon emissions reductions merely as a sensitivity case. Treating carbon emissions as zero cost emissions could result in investments that prove quite costly in the future.

Regulatory uncertainty associated with climate change clearly presents a planning conundrum; however, it is not a reason for proceeding as if no costs will be associated with carbon emissions in the future. The challenge is to forecast a reasonable range of expected costs based on analysis of the information available. This report identifies many sources of information that can form the basis of reasonable assumptions about the likely costs of meeting future carbon emissions reduction requirements. Available sources include market transactions, values used in utility planning, and modeling analyses.

Carbon markets associated with implementation of the Kyoto Protocol as well as voluntary emissions reductions have emerged. In the carbon markets, carbon traded in January 2005 at a range of $30-63/metric ton carbon ($8-17 per ton CO_2).

Some electric utilities in the United States are already incorporating carbon values into their resource planning. The values range from $4-44/metric ton carbon ($1-12 per ton CO_2). In December 2004, the California Public Utilities Commission directed utilities to

include carbon at a value between \$30-93/metric ton carbon (\$8-25 per ton CO_2) in their long term resource planning.

There are numerous studies that estimate the possible costs of carbon allowances under various policy scenarios, many of which are identified in this report. Projections of carbon costs for the year 2010 range from \$4/metric ton carbon to \$401/metric ton carbon (\$1 and \$99/ton CO_2) under different policy scenarios. Projections for carbon costs between 2020-2025 range from \$27/metric ton carbon to \$486/metric ton carbon (\$7 and \$120/ ton CO_2). Modeling results are sensitive to several factors including (1) the emissions reduction target; (2) projections of future emissions in the absence of a greenhouse gas reduction target; (3) geographic scope of trading; and (4) flexibility mechanisms such as offsets and allowance banking.

The sensitivity of the carbon price levels to the emissions reduction target can be seen by grouping the results for 2010 into two groups based upon the level of the target. For studies that analyze the costs associated with returning to the emissions levels of the year 2000 by the year 2010 or thereabouts, costs in 2010 are projected to be between \$4/metric ton carbon and \$179/metric ton carbon (\$1/ton CO_2 and \$44/ton CO_2). Studies that analyze the costs associated with a somewhat more aggressive goal of reducing emissions to near 1990 levels reveal costs in 2010 between \$4/metric ton carbon and \$401/metric ton carbon (\$1/ton CO_2 and \$99/ton CO_2).

These sources of information permit a broad assessment of potential carbon allowance prices. Indeed, incorporating reasoned assessment of future costs associated with greenhouse gas emissions is likely to be an increasingly important component of corporate success.

Table of Contents

1. Introduction

A 2002 report from the investment community identifies climate change as representing a potential multi-billion dollar risk to a variety of U.S. businesses and industries.[1] Addressing climate change presents particular risk and opportunity to the electric sector. Because the electric sector (and associated emissions) continue to grow, and because controlling emission from large point sources (such as power plants) is easier than small disparate sources (like automobiles), the electric sector is likely to be a prime component of future greenhouse gas regulatory scenarios. The report states that "climate change clearly represents a major strategic issue for the electric utilities industry and is of relevance to the long-term evolution of the industry and possibly the survival of individual companies." Risks to electric companies include the following:

- Cost of reducing greenhouse gas emissions and substantial investment in new, cleaner power production technologies and methods;
- Higher maintenance and repair costs and reliability concerns due to more frequent weather extremes and climatic disturbance; and
- Growing pressure from customers and shareholders to address emissions contributing to climate change.[2]

A subsequent report, "Electric Power, Investors, and Climate Change: A Call to Action," presents the findings of a diverse group of experts from the power sector, environmental and consumer groups, and the investment community.[3] Participants in this dialogue found that greenhouse gas emissions, including carbon dioxide emissions, will be regulated in the U.S.; the only remaining issue is when and how. Participants also agreed that regulation of greenhouse gases poses financial risks and opportunities for the electric sector. Managing the uncertain policy environment on climate change is identified as "one of a number of significant environmental challenges facing electric company executives and investors in the next few years as well as the decades to come."[4] One of the report's four recommendations is that investors and electric companies come together to quantify and assess the financial risks and opportunities of climate change.

Climate policy is likely to have important consequences for power generation costs, fuel choices, wholesale power prices and the profitability of utilities and other power plant owners. Even under conservative scenarios, additional costs could exceed 10 percent of 2002 earnings, though there are also significant opportunities. While utilities and non-utility generation owners have many options to deal with the impact of increasing prices

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[1] Innovest Strategic Value Advisors; "Value at Risk: Climate Change and the Future of Governance;" The Coalition for Environmentally Responsible Economies; April 2002.

[2] Ibid., pages 45-48.

[3] CERES; "Electric Power, Investors, and Climate Change: A Call to Action;" September 2003.

[4] Ibid., p. 6

on CO_2 emissions, doing nothing is the worst option. By making astute changes to the fuel mix and investments to refurbish existing assets, profits may also increase.[5]

Increased air emissions from fossil-fired power plants will not only increase environmental damages, they will also increase the costs of complying with future environmental regulations, costs that are likely to be passed on to all customers. Power plants built today can generate electricity for as long as 60 years or more into the future.[6] Many trends in this country show increasing pressure for a federal policy requiring greenhouse gas emissions reductions. Given the strong likelihood of future carbon regulation in the United States, the contributions of the power sector to our nation's greenhouse gas emissions, and the long lives of power plants, utilities and non-utility generation owners should be including carbon cost in all resource planning.

The purpose of this report is to identify a reasonable basis for evaluating the likely cost of future mandated carbon emissions reductions for use in long-term resource planning decisions. Section 2 and 3 discuss the role of greenhouse gases in climate. Section 4 presents information on U.S. carbon emissions. Section 5 describes international efforts to address the threat of climate change. Section 6 summarizes various initiatives at the state, regional, and corporate level to address climate change. Finally, section 7 presents information that can form the basis for forecasts of carbon allowance prices for use in utility planning.

2. The earth's climate is determined by concentrations of greenhouse gases in the atmosphere.

The earth's atmosphere serves as a kind of greenhouse. Radiation from the sun passes through the atmosphere, is absorbed by the earth, and is converted to heat. The heat is returned to the atmosphere through the emission of long wave radiation. Concentrations of certain gases in the atmosphere determine how readily the long wave radiation escapes through the atmosphere. These gases are known as "greenhouse gases" because of the similarity of their effects to the glass in a greenhouse; they include carbon dioxide, methane, nitrous oxide and others. Such gases have always been part of the atmosphere; however, since the industrial revolution in the 1700's concentrations of certain greenhouse gases in the atmosphere have risen, gradually at first and steeply since about 1850. These rising levels are due to human activities such as burning fossil fuels, deforestation, and the manufacturing of cement. Greater concentrations of greenhouse gases impede the passage of heat through the atmosphere, leading to a warming of the earth (Global Warming). This warming causes a change in the energy balance of the Earth which drives weather and precipitation around the globe. Thus, warming the Earth is expected to cause associated changes in the earth's climate (Climate Change) which directly affects the well-being of human populations and many natural systems.

[5] Innovest Strategic Value Advisors; "Power Switch: Impacts of Climate Change on the Global Power Sector;" WWF International; November 2003

[6] Biewald et. al.; "A Responsible Electricity Future: An Efficient, Cleaner and Balanced Scenario for the U.S. Electricity System;" prepared for the National Association of State PIRGs; June 11, 2004.

3. The earth's climate is changing due to human activities

International scientific consensus is that the world is warming, the climate system is changing in other ways, and that most of the warming observed over the past 50 years is due to human activities (primarily fossil fuel combustion).[7] For more than twenty years scientists from around the world have studied the potential effects on climate of the change in atmospheric greenhouse gas concentrations. These efforts are described in the next section of this report. In the past 15 years scientific consensus has emerged that increasing concentrations of greenhouse gases in the atmosphere will lead to a general warming of the earth's climate, that this general warming pattern can distort natural patterns of climate, and – most recently – that there is ample evidence that global warming is occurring.

While there are sporadic reports and articles disputing climate change, denying human contributions to climate change, or stating that global warming and climate will bring benefits, these viewpoints are outside the scientific mainstream. "Among those with the training and knowledge to penetrate the relevant scientific literatures, the debate about whether global climate is now being changed by human-produced greenhouse-gases is essentially over. Few of the climate-change 'skeptics' who appear in the op-ed pages of *The Washington Times* and *The Wall Street Journal* have any scientific credibility at all."[8]

The scientific consensus is expressed in a report issued in 2001 by the Intergovernmental Panel on Climate Change (IPCC). The World Meteorological Organization (WMO) and the United Nations Environment Programme (UNEP) established the IPCC in 1988. The purpose of the IPCC is to serve as an objective source of the most widely accepted scientific, technical and socio-economic information available about climate change, its environmental and socio-economic impacts including costs and benefits of action versus inaction, and possible response options. These international organizations determined that, because the stakes are so high and the system complex, policymakers cannot rely on popular interpretations of the evidence or on the views of an individual expert. The Panel does not conduct new research or monitor climate-related data. Its mandate is to assess, on a comprehensive, objective, open and transparent basis, the scientific, technical and socio-economic information on climate change that is available around the world in peer-reviewed literature, journals, books and, where appropriately documented, in industry

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[7] Y. Ding, J.T. Houghton, et al. editors, Climate Change 2001: The Scientific Basis (Contribution of Working Group I to the Third Assessment Report of the IPCC). Intergovernmental Panel on Climate Change. 2001. Available at: http://www.grida.no/climate/ipcc_tar/wg1/index.htm

[8] Professor John P. Holdren, "Risks from Global Climate Change. What do we know? What should we do?" Presentation to the Institutional Investors Conference on Climate Risk, November 21, 2003.

literature and traditional practices. Hundreds of scientists from around the world participate in preparing the IPCC's periodic reports.[9]

The first IPCC report, issued in 1990, confirmed that climate change is a threat and served as the basis for negotiating the overall framework for intergovernmental efforts to address climate change-the United Nations Framework Convention on Climate Change (UNFCCC).[10] The Second Assessment Report, Climate Change 1995, provided key input to the negotiations that led to the adoption of the Kyoto Protocol to the UNFCCC in 1997. The Third Assessment Report, described below, was issued in 2001. The Fourth Assessment Report is anticipated in 2007.

In 2001 the IPCC issued its Third Assessment Report (TAR). The Report reaches a number of important conclusions regarding forecasted and observed climate change. The TAR states that:

The earth's climate will change:

- Climate will change more rapidly than previously expected.
- Global mean surface temperatures are projected to increase by 1.4–5.8 degrees C by 2100 (the fastest rate of change since end of the last ice age).
- Global mean sea levels are expected to rise by 9–88 cm by 2100.
- Rainfall patterns will change.
- Variability of the climate will increase—resulting in greater threat of extreme weather events.
- Extreme events that are likely to increase include maximum temperatures, precipitation events, drying and drought, cyclone intensity, and precipitation intensities.
- There is a possibility of threshold events and irreversible events (changing Gulf Stream, collapse of large ice sheets, and others)
- Stopping growth in greenhouse gas emission concentrations is expected to lead to different equilibrium temperatures, depending on the stabilization level. For example, stabilization of atmospheric greenhouse gas concentrations at 450ppm is likely to lead to equilibrium temperature increases from 1990 levels of between 1.5 °C and 3.9 °C. Stabilization at 1000ppm is would lead to equilibrium temperature increases from 1990 levels of 3.5 °C and 8.7 °C. Stabilization at these levels requires a reduction from 1990 emission levels within a few decades or two centuries, respectively. The greater the global temperature rise, the greater will be the impacts on climate as a whole, not just temperatures.

Climate change is already evident

- Global average surface temperature has increased 0.6°C (±0.2°C) in the last century.

[9] Intergovernmental Panel on Climate Change, "Introduction to the Intergovernmental Panel on Climate Change." 2003 edition. Available at www.ipcc.ch/about/beng.pdf. See also, "16 Years of Scientific Assessment in Support of the Climate Convention." IPCC. December 2004. Available at http://www.ipcc.ch/about/anniversarybrochure.pdf

[10] The United States ratified the UNFCC in 1992.

- The 1990s was the warmest decade and 1998 the warmest year in the instrumental record, which began in 1861.
- Snow cover and ice extent, both polar and in glaciers, have decreased.
- Global average sea level has risen.
- Other aspects of climate that have changed in certain areas of the globe include increased precipitation, increased frequency of heavy precipitation events, increase in cloud cover, and increases in the frequency and intensity of droughts in parts of Asia and Africa.
- Observed changes in regional climate have affected many physical and biological systems, and there are preliminary indications that social and economic systems have been affected.

Climate change will lead to greater cost and suffering than benefits. Poorer people and countries are the most vulnerable.

- Humans are directly affected by climate. Increasing rain, temperature, storms, and climate variability will all affect individual lives as well as socio-economic systems.
- Human health will be affected by climate change through changes in ranges of disease, water-borne pathogens, water quality, and air quality.
- Human economic systems and agriculture will be affected by changes in food availability and quality, crop yields, water shortages and disruption of ecosystems.

Since the release of the IPCC's Third Assessment Report in 2001, additional scientific evidence has provided further evidence of global warming. Last year, 2004, was the fourth warmest year in the temperature record since 1861 just behind 2003. Nineteen ninety-eight was the single warmest year during that period. With the exception of 1996, the years from 1995-2004 were among the warmest 10 years on record.[11] The National Air and Space Administration (NASA) has determined that 2004 was the fourth-warmest year since temperature measurement began in the 19th century, marked by particularly warm weather in Alaska, the Caspian Sea region and the Antarctic Peninsula. According to NASA, last year's temperatures continued a 30-year rise that is caused primarily by increasing greenhouse gases in the atmosphere.[12] Other reports indicate that:

- The percentage of Earth's land area stricken by serious drought more than doubled from the 1970s to the early 2000s.[13]
- The arctic is warming almost twice as fast as the rest of the world.[14]

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[11] World Meteorological Organization, "Global Temperature in 2004 Fourth Warmest," December 15, 2004. Press release on occasion of WMO annual Statement on the Status of the Global Climate in 2004.

[12] NASA Global Temperature Trends: 2004 Summation. Released February 8, 2005. Available at: http://www.nasa.gov/vision/earth/lookingatearth/earth_warm.html

[13] National Center for Atmospheric Research – National Science Foundation, "Climate change major factor in drought's growing reach" January 10, 2005 press release.

[14] Arctic Council – "Impacts of a Warming Arctic – Arctic Climate Impact Assessment" November 2004.

- Storm & flood damages are soaring.[15] While some of this is known to be due to increasing construction in flood plains and beach fronts, insurers more and more frequently identify climate change as a major risk factor in property damage.

Other observed changes documented in scientific analyses include: evaporation and rainfall are increasing; more of the rainfall is occurring in downpours; permafrost is melting; corals are bleaching; glaciers are retreating; sea ice is shrinking; sea level is rising; and wildfires are increasing.[16]

Taken together, the TAR, and subsequent scientific analyses indicate a clear pattern of global warming and on-going climate change. According to results of climate modeling, these changes are only the beginning of things to come. The TAR emphasizes that decision making "has to deal with uncertainties including the risk of non-linear and/or irreversible changes, entails balancing the risks of either insufficient or excessive action, and involves careful consideration of the consequences (both environmental and economic), their likelihood, and society's attitude towards risk."[17]

4. U.S. carbon emissions.

The United States contributes more than any other nation, by far, to global greenhouse gas emissions on both a total and a per capita basis. The United States contributes 23 percent of the world CO_2 emissions from fossil fuel consumption, but has only 4.6 percent of the population.

Table 2: U.S. Population and CO_2 emissions for 2002

	World	United States
CO_2 Emissions (million metric tons)	24,533	5,749
U.S. percentage of world emissions	23.4%	
Population	6,417,784,929	287,941,220
U.S. percentage of world population	4.5%	
Per capita CO_2 emissions	3.93	19.97

Sources: EIA International Carbon Dioxide Emissions from the Consumption and Flaring of Fossil Fuels 1980-2002, 2004;[18] *US Census Bureau population estimate for 2002.*

[15] See, e.g. Munich Re, *Topics Geo*, "Annual Review of Natural Catastrophes 2003," stated that economic losses due to natural hazards in 2003 rose to over $65 billion (up from $55 billion in 2002).

[16] The Natural Resources Defense Council has a useful compilation of scientific studies organized by date at www.nrdc.org/globalWarming/

[17] IPCC; "Climate Change 2001: Synthesis Report – Summary for Policy Makers;" 2001. Page 3.

[18] EIA Table H.1co2 World Carbon Dioxide Emissions from the Consumption and Flaring of Fossil Fuels, 1980-2002 (posted June 9, 2004).

In 2002 the U.S. electric sector emitted 2,256.4 million metric tons CO_2.[19] These emissions represent 39 percent of U.S. total CO_2 emissions. Coal-fired power plants were responsible for 83 percent of US electric sector emissions.

Recent analysis has shown that in 2002, power plant CO_2 emissions were 25 percent higher than they were in 1990.[20] Furthermore, while the carbon intensity of the U.S. economy (carbon emissions per unit of GDP) fell by 12 percent between 1991 and 2002, the carbon intensity of the electric power sector held steady. This is because the carbon efficiency gains from the construction of efficient and relatively clean new natural gas plants have been offset by increasing reliance on existing coal plants. Since federal acid rain legislation was enacted in 1990, the average rate at which existing coal plants are operated increased from 61 percent to 72 percent. Power plant air emissions are concentrated in states along the Ohio River Valley and in the South. Five states -- Indiana, Ohio, Pennsylvania, Texas, and West Virginia -- are the source of 30 percent of the electric power industry's NOx and CO_2 emissions, and nearly 40 percent of its SO_2 and mercury emissions.

5. Governments worldwide have agreed to respond to climate change by reducing greenhouse gas emissions

The prospect of global warming and associated climate change has triggered one of the most comprehensive international treaties on environmental issues.[21] The First World Climate Conference was held in 1979. In 1988, the World Meteorological Society and the United Nations Environment Programme created the Intergovernmental Panel on Climate Change to evaluate scientific information on climate change. Subsequently, in 1992 countries around the world, including the United States, adopted the United Nations Framework Convention on Climate Change.

The United Nations Framework Convention on Climate Change has almost worldwide membership (including the U.S.); and, as such, is one of the most widely supported of all international environmental agreements. Parties to this Convention agree that "The Parties should protect the climate system for the benefit of present and future generations of humankind, on the basis of equity and in accordance with their common but differentiated responsibilities and respective capabilities."[22] The Convention establishes an objective and principles, and includes commitments for different groups of countries

[19] EIA; "Emissions of Greenhouse Gases in the United States 2003;" Energy Information Administration; December 2004. Table 11.

[20] Goodman, Sandra; "Benchmarking Air Emissions of the 100 Largest Electric Generation Owners in the U.S. - 2002;" CERES, Natural Resources Defense Council (NRDC), and Public Service Enterprise Group Incorporated (PSEG); April 2004.

[21] For comprehensive information on the UNFCC and the Kyoto Protocol, see UNFCC, "Caring for Climate: a guide to the climate change convention and the Kyoto Protocol," issued by the Climate Change Secretariat (UNFCC) Bonn, Germany. 2003. This and other publications are available at the UNFCCC's website: http://unfccc.int/.

[22] From Article 3 of the United Nations Framework Convention on Climate Change.

Table 1: Emission reduction targets under the Kyoto Protocol[26]

Country	Target: change in emissions from 1990** levels by 2008/2012
EU-15*, Bulgaria, Czech Republic, Estonia, Latvia, Liechtenstein, Lithuania, Monaco, Romania, Slovakia, Slovenia, Switzerland	-8%
US***	-7%
Canada, Hungary, Japan, Poland	-6%
Croatia	-5%
New Zealand, Russian Federation, Ukraine	0
Norway	+1%
Australia***	+8%
Iceland	+10%

** The EU's 15 member States will redistribute their targets among themselves, as allowed under the Protocol. The EU has already reached agreement on how its targets will be redistributed.*
*** Some EITs have a baseline other than 1990.*
**** The US and Australia have indicated their intention not to ratify the Kyoto Protocol.*

6. State governmental agencies, shareholders, and corporations are working to reduce greenhouse gas emissions from the U.S.

The Federal Government in the United States has failed to act with regard to climate change, despite scientific consensus on the risks and the nation's disproportionate contribution to greenhouse gas emissions. There have been some initiatives at the federal level to adopt carbon emissions reduction goals; however they have not yet had sufficient support within the Administration and Congress. Landmark legislation that would regulate carbon, the Climate Stewardship Act (S.139), was introduced by Senators McCain and Lieberman in 2003, and received 43 votes in the Senate. A companion bill was introduced in the House by Congressmen Olver and Gilchrest. The bill was reintroduced in the 109th Congress on February 10, 2005, and other legislative initiatives on climate change are also under debate in the Spring of 2005. As currently proposed, the Climate Stewardship Act would create a national cap and trade program to reduce CO_2 to year 2000 emission levels over the period 2010 to 2015. While McCain-Lieberman's bill failed to pass this year, the Senate did pass a "Sense of the Senate" resolution affirming the science of climate change and the need for mandatory caps on greenhouse gas emissions.[27] Legislation proposed by the Bush Administration, that would set a national cap on emissions of sulfur dioxide, nitrogen oxides, and mercury (titled "Clear Skies"), has met with stiff resistance due to its failure to address carbon dioxide.

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[26] Background information at: http://unfccc.int/essential_background/kyoto_protocol/items/3145.php

[27] Kintisch, Eli. "Climate Change: Senate Resolution Backs Mandatory Emission Limits." *Science*, Vol. 309, Issue 5731, 32, 1 July 2005. Available at: http://www.sciencemag.org/cgi/content/full/309/5731/32a?rss=1

according to their circumstances and needs.[23] Industrialized nations and Economies in Transition, known as Annex I countries in the UNFCCC, agree to adopt climate change policies to reduce their greenhouse gas emissions. Industrialized countries that were members of the Organization for Economic Cooperation and Development (OECD) in 1992, called Annex II countries, have the further obligation to assist developing countries with emissions mitigation and climate change adaptation.

After over two years of negotiations through the Conference of Parties (COP), Parties to the UNFCCC adopted the Kyoto Protocol on December 11, 1997. The Kyoto Protocol supplements and strengthens the Convention; the Convention continues as the main focus for intergovernmental action to combat climate change. The Protocol establishes legally-binding targets to limit or reduce greenhouse gas emissions.[24] The Protocol also includes various mechanisms to cut emissions reduction costs. Specific rules have been developed on emissions sinks, joint implementation projects, and clean development mechanisms. The Protocol envisions a long-term process of five-year commitment periods. Negotiations on targets for the second commitment period (2013-2017) are beginning.

The Kyoto targets are shown below, in Table 1. Only Parties to the Convention that have also become Parties to the Protocol (i.e. by ratifying, accepting, approving, or acceding to it), are bound by the Protocol's commitments, following its entry into force in February 2005.[25] The individual targets for Annex I Parties add up to a total cut in greenhouse-gas emissions of at least 5 percent from 1990 levels in the commitment period 2008-2012.

Only a few industrialized countries have not signed the Kyoto Protocol; these countries include the United States, Australia, and Monaco. Of these, the United States is by far the largest emitter with 36.1 percent of Annex I emissions in 1990; Australia and Monaco were responsible for 2.1 percent and less than 0.1 percent of Annex I emissions, respectively. The United States did not sign the Kyoto protocol, stating concerns over impacts on the U.S. economy and absence of binding emissions targets for countries such as India and China. Many developing countries, including India, China and Brazil have signed the Protocol, but do not yet have emission reduction targets. Still others have already demonstrated success in addressing climate change.

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[23] For example, one of obligations of the U.S. and other industrialized nations is to submit National Report describing actions it is taking to implement the Convention

[24] Greenhouse gases covered by the Protocol are CO_2, CH_4, N_2O, HFCs, PFCs and SF_6.

[25] Entry into force required 55 Parties to the Convention to ratify the Protocol, including Annex I Parties accounting for 55 percent of that group's carbon dioxide emissions in 1990. This threshold was reached when Russia ratified the Protocol in November 2004. The Protocol entered into force February 16, 2005.

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As of February 16, 2005, when the Kyoto Protocol went into effect, U.S.-based companies that have subsidiaries in the EU are "subject to CO_2 emissions caps, but cannot take advantage of low-cost emission reductions at their facilities in the United States or elsewhere."[28] American companies that are consequently disadvantaged in the EU may start to put pressure on the Administration for a national greenhouse gas policy.

Some individual states and regions, however, have taken the initiative in this area and are adopting their own greenhouse gas mitigation policies. Many corporations are also taking initiative either under pressure from shareholder resolutions or as corporate policy, in anticipation of mandates to reduce emissions of greenhouse gases. These efforts are described below.

6.1 State and regional policies

In the absence of Federal initiative on climate change, individual states in this country have been the leaders on climate change policies:

- In 1997 **Oregon** established the first formal standard for CO_2 emissions from new electricity generating facilities in North America.[29] The standard holds any proposed new or expanded power plant to a CO_2 emissions rate of 0.675 pounds per kWh, which is 17 percent less than the most efficient natural gas-fired plant currently operating in the U.S. At the same time, the state also created a non-profit corporation known as the Climate Trust to implement CO_2 offset projects with funds provided by the electric generating industry. A generator can choose to either meet the emissions standard or donate funds to the Climate Trust. The donation level was originally set at $0.57 per ton of CO_2, but is subject to change based on the actual cost of CO_2 offsets.
- In 2001 **Massachusetts** was the first state to establish a cap on CO_2 emissions from fossil fueled power plants. The Massachusetts Department of Environmental Protection issued "Emissions Standards for Power Plants" (310 CMR 7.29) in April 2001. This multi-pollutant legislation requires emission reductions including CO_2 reductions from the six highest emitting power plants in the state. The CO_2 standard of 1,800 lbs/MWh by 2006 represents a 10 percent reduction from the historic baseline (1997-1999). Facilities are allowed to meet their reduction requirements through offsite CO_2 reductions, subject to DEP approval. The compliance deadline is extended to October 2008 for any facility that undergoes repowering. In addition to this legislation, the state's Energy Facilities Siting Board requires *new* power plants with a capacity greater than 100 MW to offset 1 percent of the facility's CO_2

[28] Fontaine, Peter, "Greenhouse –Gas Emissions: A New World Order," Public Utilities Fortnightly, February 2005.

[29] Anne Egelston, "Oregon, Massachusetts Lead the Way in GHG Reductions," *Environmental Finance*, July-August 2001.

emissions for the next 20 years, as long as the cost of offsets does not exceed $1.50 per ton.

- In July 2002, **California** adopted a first-of-a-kind law (AB 1493) to limit the emissions of CO_2 from new cars and trucks sold in the state. The law requires the California Air Resources Board to write regulations to achieve the maximum feasible reduction in CO_2 emissions from cars and trucks, beginning with the 2009 model year. Since that time, New York, New Jersey, Rhode Island, Connecticut, Massachusetts, Maine, and Vermont have each agreed to adopt this standard. An Executive Order in June 2005 calls for reducing the state's emissions of greenhouse gases to 2000 levels by 2010, 1990 levels by 2020, and 80 percent below 1990 levels by 2050.
- The **New Hampshire** "Clean Power Act" (HB 284), approved in May 2002, requires CO_2 reductions from the three existing fossil-fuel power plants in the state. The law requires the plants to stabilize their CO_2 emissions at 1990 levels (approximately three percent below their 1999 levels) by the end of 2006. This CO_2 emission reduction is consistent with the Climate Change Action Plan adopted by the New England Governors and Eastern Canadian Premiers (see below). Plants have the option to reduce their emissions on site or to purchase emissions credits from outside of the state.
- In **New Jersey**, the Department of Environmental Protection released the New Jersey Sustainability Greenhouse Gas Action Plan in April 2000. The Plan provides a framework for reducing greenhouse gas emissions to 3.5 percent below their 1990 levels by 2005. Under the Plan, Public Service Enterprise Group, the state's largest utility, pledged to reduce total emissions from all of its fossil fuel-based plants by 15 percent below 1990 levels by 2005. This would require its fossil fuel-fired units to limit their CO_2 emissions to 1450 lbs/MWh in 2005, compared to 1706 lb/MWh in 1990. If PSEG fails to achieve the goal, it must pay the DEP $1 per pound/MWh it falls short of its goal, up to $1.5 million. The fund will be used to support CO_2 reduction projects within New Jersey.
- The state of **Washington** recently passed a law requiring that new power plants either mitigate or pay for a portion of their carbon emissions. Representative Jeff Morris, the bill's primary sponsor, said "Washington State is not going to solve global warming, but we are doing our part." [30]
- The **New York** Greenhouse Gas Task Force was created by Governor Pataki in June 2001. The purpose of the Task Force is to develop recommendations for ways to significantly reduce the state's emissions of greenhouse gases, and New York is currently considering whether to adopt the recommendations of the Greenhouse Gas Task Force. The 2002 State Energy Plan also recommends that the state commit to a goal of reducing greenhouse gas

[30] Washington House of Representatives Press Release, *Governor Signs Morris Bill to Clean Up Air Pollution,* March 31, 2004.

- The Governors of **California** and **New Mexico** proposed that 18 western states generate 30,000 MW of electricity from renewable source by 2015. This proposal was unanimously adopted in June 2004.[35]
- In July 2004, **California, Connecticut, Iowa, New Jersey, New York, Rhode Island, Vermont, and Wisconsin** filed a suit against five power plant owners, which together, emit 10 percent of the nation's annual CO_2. This suit seeks CO_2 emissions reductions of three percent per year for the next ten years rather than financial penalties.[36]
- In August 2001, in the first action of its kind in North America, the **New England Governors and Eastern Canadian Premiers** signed an agreement for a comprehensive regional Climate Change Action Plan.[37] The plan centers on three main goals. The short-term goal of the Plan is to reduce regional greenhouse gas emissions to 1990 levels by 2010. The mid-term goal is to reduce regional GHG emissions by at least 10 percent below 1990 levels by 2020, and establish an interactive, five-year process, starting in 2005, to adjust the goals if necessary and set future emission reduction goals. The long-term goal of the Plan is to reduce regional greenhouse gas emissions in proportions consistent with reductions necessary worldwide to eliminate any dangerous threat to the climate, which recent science suggests will require reductions of 75-85 percent below current levels. The Plan also provides for the establishment of a regional standardized inventory and registry of greenhouse gas emissions.

Actions by cities: Many cities are also adopting climate change policies. The Cities for Climate Protection Campaign (CCP), begun in 1993, is a global campaign to reduce the emissions that cause global warming and air pollution. By 1999, the campaign had engaged more than 350 local governments in this effort, who jointly accounted for approximately seven percent of global greenhouse gas emissions.[38] Over 150 cities in the U.S. have adopted plans and initiatives to reduce emissions of greenhouse gases, setting emissions reduction targets and taking measures within municipal government operations. Climate change is expected to be a major issue at the annual U.S. Conference of Mayors convention in June.[39]

All of these recent activities demonstrate that there has been growing pressure within the U.S., to adopt regulations to reduce the emissions of greenhouse gases, particularly CO_2. This pressure is likely to increase further over time, as climate change issues and

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[35] Jacobson, Sanne, Neil Numark and Paloma Sarria, "Greenhouse – Gas Emissions: A Changing US Climate," *Public Utilities Fortnightly*, February 2005.

[36] Id.

37 New England Governors and Eastern Canadian Premiers, *Climate Change Action Plan: 2001*, August 2001.

[38] Information on the Cities for Climate Protection Campaign, including links to over 150 cities that have adopted greenhouse gas reduction measures, is available at http://www.iclei.org/projserv.htm#ccp

[39] Kathy Mulady, *Seattle Post-Intelligencer*, Feb. 17, 2005.

emissions by five percent below 1990 levels by 2010, and 10 percent below 1990 levels by 2020.[31]

- In addition to the regulations and programs described above, 25 states are working with the U.S. Environmental Protection Agency ("EPA") to develop **climate action plans** that identify cost-effective options for reducing greenhouse gas emissions at the state level. At least 19 states have completed an action plan to date.
- Many states have other policies such as renewable portfolio standards and energy efficiency programs that serve to reduce CO_2 emissions from the electricity sector; and many state energy plans and initiatives cite greenhouse gas mitigation as a policy rationale or specific objective.

Action by individual states has been enhanced by several regional initiatives to reduce greenhouse gas emissions:

- **Nine Northeast and Mid-Atlantic states** (DE, ME, MA, NH, NJ, NY, RI, VT) have formed "The Regional Greenhouse Gas Initiative" (RGGI) in a cooperative effort to discuss the design of a regional cap-and-trade program initially covering CO_2 emissions from power plants in the region. Collectively, these states contribute to 9.3 percent of total US CO_2 emissions and together rank as the fifth highest CO_2 emitter in the world. Pennsylvania, Maryland, the District of Columbia, the Eastern Canadian Provinces, and New Brunswick are official "observers" in the RGGI process. The states are discussing adoption of a Memorandum of Understanding and a Model Rule in 2005. In this process, CO_2 emissions from fossil fuel fired electricity generating units will be capped at specific levels.[32]
- In September 2003, the Governors of **California, Washington, and Oregon** established the West Coast Governor's Climate Change Initiative, stating that "global warming will have serious adverse consequences on the economy, health, and environment of the west coast states, and that the states must act individually and regionally to reduce greenhouse gas emissions and to achieve a variety of economic benefits from lower dependence on fossil fuels."[33] Emissions in these three states are comparable to those of the RGGI states. RGGI and the West Coast Governors' Initiative have been communicating with regard to potentially linking their cap and trade programs.[34]

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[31] New York State Energy Research and Development Authority, *2002 State Energy Plan and Final Environmental Impact Statement*, June 2002.

[32] Information on this effort is available at www.rggi.org

[33] See letter from the California Energy Commission and the California Environmental Protection Agency to interested parties, April 16, 2004, at: http://www.energy.ca.gov/global_climate_change/westcoastgov/.

[34] Fontaine, Peter, "Greenhouse –Gas Emissions: A New World Order," *Public Utilities Fortnightly*, February 2005.

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measures for addressing them become better understood by the scientific community, by the public, and particularly by elected officials.

6.2 Investor and corporate action

Investors and corporate leaders have taken steps to manage risk associated with climate change and carbon policy. Many investors are demanding that companies take seriously the risks associated with carbon emissions. Shareholders have filed a record number of global warming resolutions for 2005 for oil and gas companies, electric power production, real estate firms, manufacturers, financial institutions and auto makers.[40] The resolutions request financial risk disclosure and plans to reduce greenhouse gas emissions. Four electric utilities-AEP, Cinergy, TXU and Southern-all agreed to shareholder requests in 2004 by promising climate risk reports. Only Southern's report has yet to be completed.

Investors are gradually becoming aware of the financial risks associated with climate change, and there is a growing body of literature regarding the financial risks to electric companies and others associated with climate change. State and city treasurers, labor pension fund officials, and foundation leaders have formed the Investor Network on Climate Risk (INCR). The INCR issued a 10-point "Call for Action" at the Institutional Investor Summit on Climate Risk at the United Nations Headquarters on Nov. 21, 2003. It urges pension and endowment trustees, fund managers, securities analysts, corporate directors and government policymakers to increase their oversight and scrutiny of the investment implications of climate change.[41] This report cites analysis indicating that carbon constraints affect market value - with modest greenhouse gas controls reducing the market capitalization of many coal-dependent U.S. electric utilities by 5 to 10 percent, while a more stringent reduction target could reduce their market value 10 to 35 percent.[42] The report recommends, as one of the steps that company CEOs should pursue, integrating climate policy in strategic business planning to maximize opportunities and minimize risks.

Institutional investors have formed The Carbon Disclosure Project (CDP), which is a coordinating secretariat for collaboration regarding climate change. Its mission is to inform investors regarding the significant risks and opportunities presented by climate change; and to inform company management regarding the serious concerns of shareholders regarding the impact of these issues on company value. In 2003, the first Carbon Disclosure Project report (CDP1) gathered the support of 35 institutional investors representing some $4.5 trillion in managed assets.

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[40] "US Companies Face Record Number of Global Warming Shareholder Resolutions on Wider Range of Business Sectors," CERES press release, February 17, 2005.

[41] Cogan, Douglas G.; "Investor Guide to Climate Risk: Action Plan and Resource for Plan Sponsors, Fund Managers, and Corporations;" Investor Responsibility Research Center; July 2004.

[42] Cogan 2004, citing Frank Dixon and Martin Whittaker, "Valuing Corporate Environmental Performance: Innovest's Evaluation of the Electric Utilities Industry," New York, 1999.

The release of the second report (CDP2), in 2004, reflected even greater participation with signatories from Africa, Asia, Europe and North America. Signatories now represent over $10 trillion in assets, and total emissions from operations reported to CDP across all sectors were roughly 13 percent of all emissions from fossil fuel combustion worldwide. The CDP2 report indicated the escalation in scope and awareness-on behalf of both signatories and respondents-can be traced to an increased sense of urgency with respect to climate risk and carbon finance in the global business and investment community. The report attributes this to developments over the past 18 months that have highlighted the social and economic costs of climate change and the risks and opportunities being created worldwide by emissions reduction policies.[43]

The California Public Employees' Retirement System (CalPERS) announced that it will use the influence made possible by its $183 billion portfolio to try to convince companies it invests in to release information on how they address climate change. The CalPERS board of trustees voted unanimously for the environmental initiative, which focuses on the auto and utility sectors in addition to promoting investment in firms with good environmental practices.[44]

Some CEOs in the electric industry have determined that inaction on climate change issues is not good corporate strategy, and individual electric companies have taken steps to reduce greenhouse gas emissions. Their actions represent increasing initiative in the electric industry to address the threat of climate change and manage risk associated with future carbon constraints. Recently, eight US-based utility companies have joined forces to create the "Clean Energy Group." This group's mission is to seek "national four-pollutant legislation that would, among other things… stabilize carbon emissions at 2001 levels by 2013." [45] In addition, Cinergy Corporation has been quite vocal on its support of mandatory national carbon regulation. Cinergy's current target is to produce 5 percent below 2000 levels by 2010 – 2012. AEP has a similar target. FPL Group and PSEG are both aiming to reduce total emissions by 18 percent between 2000 and 2008.[46] The President of Duke Energy President urges a federal carbon tax, and states that Duke should be a leader on climate change policy.[47] A fundamental impediment to action on the part of electric generating companies is the lack of clear, consistent, national guidelines so that companies could pursue emissions reductions without sacrificing competitiveness.

While statements such as these are an important first step, they are only a starting point, and do not, in and of themselves, cause reductions in carbon emissions. It is important to keep in mind the distinction between policy statements and actions consistent with those

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[43] Innovest Strategic Value Advisors; "Climate Change and Shareholder Value In 2004," second report of the Carbon Disclosure Project; Innovest Strategic Value Advisors and the Carbon Disclosure Project; May 2004.

[44] *Greenwire*, February 16, 2005

[45] Jacobson, Sanne, Neil Numark and Paloma Sarria, "Greenhouse Gas Emissions: A Changing US Climate," *Public Utilities Fortnightly*, February 2005.

[46] Ibid.

[47] Paul M. Anderson Letter to Shareholders, March 15, 2005.

statements. For example, Synapse's review of Cinergy's actions to address climate change found them to be inconsistent with public statements made by company officials.[48]

6.3 Carbon inventories

With increased attention to climate change issues comes an increasing desire and need to quantify and track greenhouse gas emissions. The California Climate Action Registry (the Registry) was established by the California Legislature as a non-profit voluntary registry for greenhouse gas (GHG) emissions.[49] The purpose of the Registry is to help companies and organizations with operations in the state to establish GHG emissions baselines against which any future GHG emission reduction requirements may be applied.

The Registry encourages voluntary actions to increase energy efficiency and decrease GHG emissions. Participants can record their GHG emissions inventory using any year from 1990 forward as a base year. The State of California promises its best efforts to ensure that participants receive appropriate consideration for early actions in the event of any future state, federal or international GHG regulatory scheme.

The Global GHG Register, launched in January 2004, is a web-based platform that allows companies to disclose their worldwide GHG emission inventories and reduction targets. It gives multinational companies the opportunity to show how much greenhouse gases their operations produce, and what they are doing about it.[50] Its structure is based on the California Climate Action Registry.[51]

Other states in the U.S. have GHG registries including New Hampshire, Wisconsin, and New Jersey, and many states have registries under development.[52]

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[48] See the testimony of Bruce Biewald on behalf of CAC/HEC filed in Indiana Utility Regulatory Commission Cause No. 42622/42718 available at http://www.synapse-energy.com/Downloads/synapse-testimony-bb-cac-hec-psi-public.pdf

[49] The California Climate Action Registry (the Registry) was established by SB1771, with technical changes to the statute in SB527. SB 527 was signed by Governor Gray Davis on October 13, 2001, finalizing the structure for the Registry.

[50] For more information see: http://www.weforum.org/site/homepublic.nsf/Content/Global+Greenhouse+Gas+Register

[51] California Climate Action Registry, "California Registry's Online Tool To Serve As Foundation for Global Greenhouse Gas Register," December 9, 2003 press release.

[52] More information on state GHG registries is available at the Greenhouse Gas State Registry Collaborative (Northeast States for Coordinated Air Use Management). http://www.nescaum.org/Greenhouse/Registry/

7. Estimating the cost of reducing carbon emissions

Uncertainty about the form of future greenhouse gas reduction policies poses a planning challenge for generation owning entities in the electric sector including utilities and non-utility generators. Nevertheless, it is not reasonable or prudent to assume a carbon cost of $0 in planning decisions. There is clear evidence of climate change, federal legislation has been under discussion for the past few years, state and regional regulatory efforts are currently underway, investors are increasingly pushing for companies to address climate change, and the electric sector is likely to constitute one of the primary elements of any future regulatory plan. In this context and policy climate, utilities and non-utility generators must develop a reasoned assessment of the costs associated with expected emissions reductions requirements.

This is particularly important in an industry where capital stock has a lifetime of 30 or more years. An analysis of capital cycles in the electric sector finds that "external market conditions are the most significant influence on a firm's decision to invest in or decommission large pieces of physical capital stock.[53] Failure to adequately assess market conditions, including the potential cost increases associated with likely regulation, poses a significant investment risk for utilities. It would be imprudent for any company investing in plants in the electric sector, where capital costs are high and assets are long-lived, to ignore policies that are inevitable in the next twenty years.

Evidence suggests that a utility's overall compliance decisions will be more efficient if based on consideration of several pollutants at once, rather than addressing pollutants separately. For example, in a 1999 study EPA found that pollution control strategies to reduce emissions of nitrogen oxides, sulfur dioxide, carbon dioxide, and mercury are highly inter-related, and that the costs of control strategies are highly interdependent.[54] The study found that the total costs of a coordinated set of actions is less than that of a piecemeal approach, that plant owners will adopt different control strategies if they are aware of multiple pollutant requirements, and that combined SO_2 and carbon emissions reduction options lead to further emissions reductions.[55] Similarly, in one of several studies on multi-pollutant strategies, the Energy Information Administration (EIA) found that using an integrated approach to NO_x, SO_2, and CO_2, is likely to lead to lower total costs than addressing pollutants one at a time.[56] While these studies clearly indicate that federal emissions policies should be comprehensive and address multiple pollutants, they also demonstrate the value of including future carbon costs in current resource planning activities.

There are a variety of sources of information that form a basis for developing a reasonable estimate of the cost of carbon emissions for utility planning purposes. Useful

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[53] Lempert, Popper, Resitar and Hart, "Capital Cycles and the Timing of Climate Change Policy." Pew Center on Global Climate Change, October 2002. page

[54] US EPA, *Analysis of Emissions Reduction Options for the Electric Power Industry,* March 1999.

[55] US EPA, *Briefing Report*, March 1999.

[56] EIA, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*. December 2000.

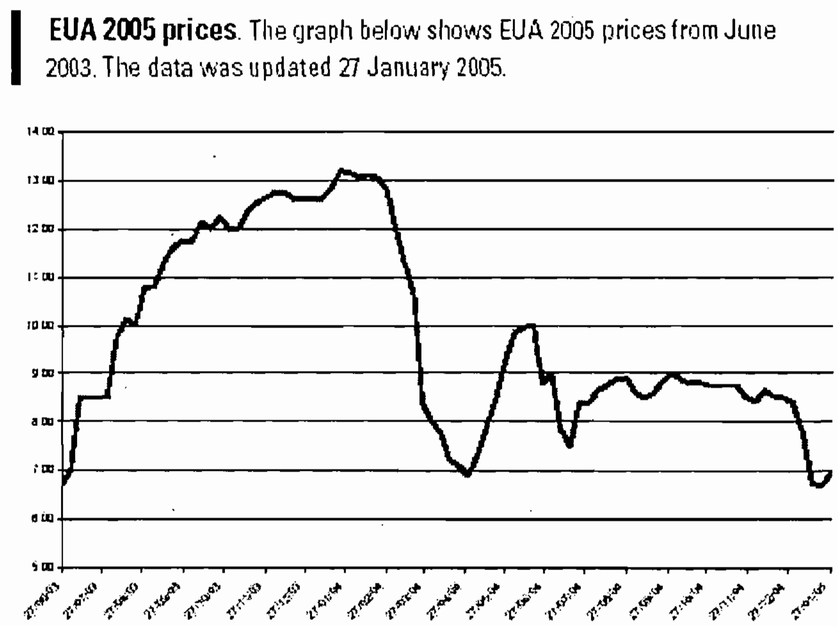
sources include recent market transactions in carbon markets, values that are currently being used in utility planning, and costs estimates developed through scenario modeling.

7.1 Market transactions

Implementation of the Kyoto Protocol has moved forward with great progress in recent years. Countries in the European Union (EU) are now trading carbon in the first international emissions market, the EU Emissions Trading Scheme (ETS), which officially launched on January 1, 2005. This market, however, was operating before that time – Shell and Nuon entered the first trade on the ETS in February 2003. Traded volumes in the EU ETS totaled approximately 600,000 tons of CO_2 in 2003, with prices ranging from about 5-13 euros per ton CO_2. Most of these trades were on a forward basis with payment on delivery. Trading volumes have increased steadily throughout 2004 and totaled approximately 8 million tons CO_2 in that year. [57]

Eight exchanges and 11 brokerages are planning to take active roles in the acceleration of the carbon market. One financial index for EU allowances (EUA) is called the Carbon Market Index. Figure 1 shows Carbon Market Index data as of January 27, 2005.

Figure 1. The Carbon Market Index for EU Allowances as of January 27, 2005 – Euros per ton CO_2.[58]



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[57] "What determines the Price of Carbon," Carbon Market Analyst, *Point Carbon*, October 14, 2004.

[58] Allan, Andrew, op. cit.

During the second half of 2004, carbon trades ranged between 6.75 to just over 13 euros per ton CO_2. This is equivalent to approximately $8–17 US. Volume in the carbon market is high, with more than 5 million tons being traded in the month of January 2005 alone. Trading volume is most liquid in the near term (2005-2007), yet trades do exist out to the year 2008, priced at approximately 9 euros/ton CO_2 ($11.50 US). [59, 60]

Table 3: Closing prices of CO_2 allowances as of January 27, 2005. [61]

Delivery Date	Last Price
EU 2005	6.95
EU 2006	6.98
EU 2007	7.05

7.2 Values in utility planning

The costs of complying with greenhouse gas emission reduction targets are receiving renewed attention in electric company planning. Most recently, the California Public Utility Commission has directed utilities to determine an appropriate value, within an identified range, for purposes of long term planning. Several utilities have already included a value to reflect the financial risk of future carbon emissions reduction requirements.

The California PUC has developed an imputed cost for GHG emissions, for use in long term utility planning.[62] The Commission's decision requires the state's largest electric utilities (PG&E, SCE, and SDG&E) to factor the financial risk associated with greenhouse gas emissions into new long-term power plant investments, and long-term resource plans. The Commission has told utilities to include a value between $8–25/ton CO_2 in their submissions, and to justify their selection of a number. In its decision, the Commission cites various estimates of carbon compliance costs submitted in the proceeding. The various estimates, ranging from $8/ton CO_2 in 2004 to a high of $36/ton CO_2 in 2020, are presented in Table 4, below.

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[59] Andrew, "Point Carbon to launch volume-weighted EU ETS index," Carbon Market Europe, *Point Carbon*, January 28, 2005.

[60] Conversion as of February 9, 2005, wherein 1 Euro = 1.27 US dollars..

[61] Allan, Andrew, op. cit..

[62] California Public Utilities Commission, Decision 04-12-048, December 16, 2004

Table 4: Values for CO_2 in long term planning considered by the CPUC

Source Document	Value
Final E3 Avoided Cost Report	$8/ton C02 2004 $12.50 by 2008 $17.50 by 2013
PG&E internal RFO review	$8
PacifiCorp 2003 IRP -	$8
NRDC opening brief -	$12 beginning 2008
Idaho Power Co IRP -	$12.30 beginning 2008
EIA analysis of proposed legislation143	$15-$25 in 2010 $14-$36 in 2020

Several electric utilities and electric generation companies have incorporated assumptions about carbon regulation and costs in their long term planning, and have set specific agendas to mitigate shareholder risks associated with future U.S. carbon regulation policy. Table 5 illustrates the range of carbon cost values, both in $/metric ton C and $/ton CO_2, that are currently being used in the industry for both resource planning and modeling of carbon regulation policies.

Table 5: CO_2 costs in long term resource plans[63]

Company	CO_2 emissions trading assumptions for various years	$/metric ton carbon
PG&E	$8/ton (2008)	$29
Avista	$1-11/ton (2004-2023)	$5-40
Portland's General Electric	$10/ton (2010)	$37
Xcel	$6-12/ton (2009)	$22-44
Idaho Power	$12.30/ton (2008). Also evaluated scenarios with carbon dioxide at $12.30 per ton and $49.21 per ton.	$45. Highest scenario is $180
Pacificorp – subsidiary of Scottish Power	$8/ton in 2003 IRP, also evaluated scenarios with carbon dioxide at $2, $25, and $40/ton.	$29 up to a high off $147

These early efforts by utilities lay the groundwork for the increased use of carbon value estimates in utility planning and in other elements of corporate strategy in the electric sector.

[63] Wiser, Ryan and Mark Bolinger, *An Overview of Alternative Fossil Fuel Price and Carbon Regulation Scenarios*, Lawrence Berkeley National Laboratory, October 2004. See, also, PacifiCorp, *Integrated Resource Plan 2003*, pages 45-46, and Idaho Power Company, *2004 Integrated Resource Plan Draft*, July 2004, page 59.

Table 6: Estimates of U.S. Allowance Costs ($US2004/metric ton Carbon)

Study	2010 Emissions Goal	2010 Allowance Price Range	2020-2025 Allowance Price Range**
		$2004/mtC	$2004/mtC
SEMF -Rice 98	7% below 1990 levels 2008-2012	4-191	-
SEMF -Asia Pacific	7% below 1990 levels 2008-2012	48-85	-
SEMF -MS MRT	7% below 1990 levels 2008-2012	36-323	42-369
SEMF - Pacific Northwest	7% below 1990 levels 2008-2012	33-313	-
SEMF -MIT Emissions	7% below 1990 levels 2008-2012	137-325	-
EIA '98	24% above 1990 levels to 7% below 1990 levels 2008-2012	77-401	-
EIA '99	24% above 1990 levels to 7% below 1990 levels 2008-2012	71-364	-
ICF '04	1990 levels in 2010	47-50	79-84
Springer summary of 25 models*	Kyoto targets in 2010	4-324	-
EIA '03	2000 levels 2010, 1990 levels in 2016	43-93	167-314
EIA '04	2000 levels 2010 and beyond	58	113
MIT '03	2000 levels 2010 and beyond	19-184	61-500
Tellus '03	2000 levels 2010, 1990 levels 2016	27-31	58-85
Tellus '04	2000 levels 2010 and beyond	35	81
CRA	2000 levels starting 2010, with safety valve	17	17-28
EIA '03b	2001 emissions in 2013	4-70	27-143
ICF '04b	2000 levels in 2010	13	21
RFF***	6% reduction from BAU scenario, starting 2008	26-41	-

* *Springer summary allowance prices are global rather than U.S.*
** *MIT '03, MS MRT, CRA, Tellus, results for 2020; EIA '03, EIA '03b, and '04 results for 2025.*
*** *RFF results for 2012. Study focuses relative costs of allocation methods.*

The Stanford Energy Modeling Forum organized a comparative set of analyses, published in 1999, of the economics and energy sector impacts of the Kyoto Protocol on Climate Change.[64] The objectives of this study, were to (1) identify policy-relevant insights and analyses that are robust across a wide range of models, (2) provide explanations for differences in results from different models, and (3) identify priorities for future research. Nine teams of modelers participated in this effort. Each team ran the same four "core" scenarios, and also ran other scenarios that their models were well suited to explore. The four "core" scenarios were (1) a modeler's reference case (assumptions determined by each team), (2) no emissions trading, (3) full Annex I trading, and (4) full global trading. All of the "core" scenarios assumed that the Kyoto targets would be in place for 2010 and beyond.

[64] International Association for Energy Economics, "The Costs of the Kyoto Protocol: A Multi-Model Evaluation," *The Energy Journal*, 1999.

7.3 Analyses of carbon emissions reduction costs

There have been several studies and analyses that project the cost of reducing carbon emissions to meet various emissions targets. Some of these analyses focus on the Kyoto Protocol, assuming a 7 percent emissions reduction from 1990 levels in the U.S. Other studies focus on the McCain Lieberman Bill as proposed in 2003, which would require that emissions levels in 2010 be the same as emissions levels in 2000 in the U.S. Yet another study is designed to analyze the impacts of allowance allocation methods, rather than to project carbon costs of a particular emissions reduction goal. These studies reveal a wide range of cost estimates. While it is not possible, given current uncertainties about the goal and design of carbon regulation, to pinpoint emissions reduction costs, the studies provide a useful source of information. In addition to establishing ranges of cost estimates, the studies give a sense of which factors affect future costs of reducing carbon emissions.

Table 6 presents results for several of these studies in constant 2004 dollars per metric ton of carbon. A similar table converted into dollars per ton CO_2 is contained in the Appendix to this report.

The studies produced a wide range of estimates for the cost of meeting the Kyoto Protocol emissions reductions targets. This range is due to differing assumptions about the geographical scope of emissions trading as well as other elements of program implementation. The range of estimates is also due to features of the models. One of the major determinants of the cost of achieving reductions in each region in the reference case is the level of emissions projected in the reference case for each region. The variation in projected emissions stems from different assumptions about economic growth, fuel costs, capital stock turnover and other factors.

Most of the reference case runs project a 30 percent increase in U.S. carbon emissions from 1990 to 2010 (range is 21 percent-36 percent) under existing emissions regulations. The price projections range from \$36-\$180/metric ton carbon or scenarios with full global trading (\$25/metric ton carbon to \$125/metric ton carbon in 1990 dollars). Projections for "no trading" scenarios range from \$108 to \$585/metric ton carbon (\$75-\$405/metric ton carbon in 1990 dollars). Virtually all the teams were uncomfortable with the "full global trading" scenario since they considered it an unrealistic outcome of the negotiation process.

In 2003, Urs Springer of the University of St. Gallen in Switzerland compiled a summary of results from 25 models of the market for tradable greenhouse gas emission permits under the Kyoto Protocol.[65] Springer provides an overview of the results and methods used in the studies. Results range from \$4 to 96 per metric ton carbon under global trading scenarios where all countries have to meet Kyoto targets in 2010 (rather than on average between 2008 and 2012 – as in the Protocol). Results range from \$13 to \$324 per metric ton carbon in scenarios with Annex B CO_2 trading only. (See, e.g. Tables 1 and 2.)

The United States Energy Information Administration (EIA) has performed several studies projecting costs associated with compliance with the Kyoto Protocol. In 1998, EIA performed a study analyzing allowance costs associated with six scenarios ranging from emissions in 2010 at 24 percent above 1990 emissions levels, to emissions in 2010 at 7 percent below 1990 emissions levels.[66] In 1999 EIA performed a very similar study, but looked at phasing in carbon prices beginning in 2000 instead of 2005 as in the original study.[67]

There have also been several studies in the U.S. of the costs to comply with legislation proposed by Senators McCain and Lieberman. As originally proposed, the McCain Lieberman legislation would cap 2010 emissions at 2000 levels, and would reduce allowed emissions in 2016 to 1990 levels. In 2003, the Energy Information Administration conducted a study of the McCain Lieberman legislation. EIA ran several sensitivity cases exploring the impact of technological innovation, gas prices, allowance

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[65] Springer, Urs; "The Market for Tradable GHG Permits Under the Kyoto Protocol: a Survey of Model Studies;" *Energy Economics* 25 (2003) 527-551.

[66] EIA, "Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity," October 1998. SR/OIAD/98-03

[67] EIA, "Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protcol," July 1999. SR/OIAF/99-02.

auction, and flexibility mechanisms (banking and international offsets). The current version of the legislation would cap emissions in 2010 at 2000 levels, with no further ratchet. EIA conducted a further analysis of the McCain Lieberman legislation in comparison with the Administration's Clear Skies Act and the Clean Air Planning Act of 2003.[68] The Clean Air Planning Act would cap 2013 emissions at 2001 levels.

Researchers at the Massachusetts Institute of Technology also analyzed potential costs of the McCain Lieberman legislation in 2003.[69] MIT held emissions for 2010 and beyond at 2000 levels (not modeling the second step of the proposed legislation). Due to constraints of the model, the MIT group studied an economy-wide emissions limit rather than a limit on the energy sector. A first set of scenarios considers the cap tightening in Phase II and banking. A second set of scenarios examines the possible effects of outside credits. And a final set examines the effects of different assumptions about baseline gross domestic product (GDP) and emissions growth.

The Tellus Institute conducted two studies for the Natural Resources Defense Council of the Climate Stewardship Act and the Climate Stewardship Act Amendment (July 2003 and June 2004).[70] In its analysis of the Climate Stewardship Act, Tellus relied on a modified version of NEMS to model all sectors with Base Case using data from 2003. Tellus then modeled two policy cases. The "Policy Case" scenario included the provisions of the Climate Stewardship Act (S.139) as well as oil savings measures, a national renewable transportation fuel standard, a national RPS, and emissions standards contained in the Clean Air Planning Act. The "Advanced Policy Case" includes a more aggressive oil savings policy that would start at 25 mpg in 2005, increasing to 45 mpg in 2025.

In 2003 ICF was retained by the state of Connecticut to model a carbon cap across the 10 northeastern states. This analysis modeled a carbon cap on electrical generation in a ten-state region in the Northeastern U.S. The cap is set at 1990 levels in 2010, 5 percent below 1990 levels in 2015, and 10 percent below 1990 levels in 2020. The use of offsets is phased in with entities able to offset 5 percent or their emissions in 2015 and 10 percent in 2020. The CO_2 allowance price, in $US2003, for the 10-state region increases over the forecast period in the policy case, rising from $7.38/metric ton in 2010 to $9.59/metric ton in 2015 to $12.11/metric ton in 2020 (page 3.3-27). This equates to $28/metric ton carbon in 2010 ($US2004) and $45/metric ton carbon ($US2004).[71]

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[68] EIA, *Analysis of S. 485, the Clear Skies Act of 2003, and S. 843, the Clean Air Planning Act of 2003*, EIA Office of Integrated Analysis and Forecasting, SR/OIAF/2003-03, September 2003.

[69] Paltsev, Sergei; Reilly, John M.; Jacoby, Henry D.; Ellerman, A. Denny; Tay, Kok Hou; *Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: the McCain-Lieberman Proposal.* MIT Joint Program on the Science and Policy of Global Change; Report No. 97; June 2003.

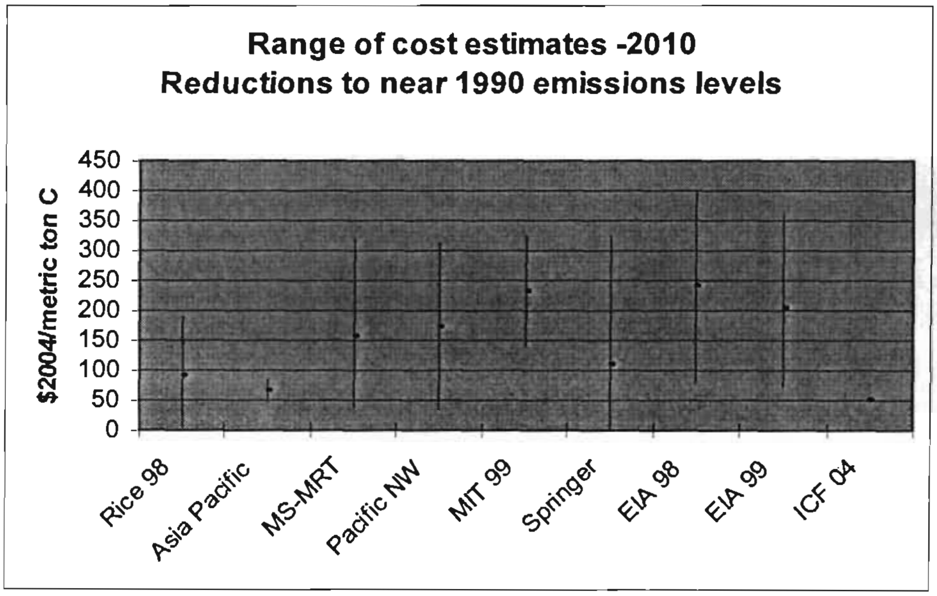
[70] Bailie et al., *Analysis of the Climate Stewardship Act,* July 2003; Bailie and Dougherty, *Analysis of the Climate Stewardship Act Amendment*, Tellus Institute, June, 2004. Available at http://www.tellus.org/energy/publications/McCainLieberman2004.pdf

[71] Center for Clean Air Policy, *Connecticut Climate Change Stakeholder Dialogue: Recommendations to the Governors' Steering Committee*, January 2004, p. 3.3-27.

Other studies have focused on specific issues associated with implementing a carbon cap. Resources for the Future (RFF) analyzed the effect of various allowance allocation methods on the cost of carbon emission trading.[72] Charles River Associates analyzed the McCain Lieberman legislation with a safety valve of $15/metric ton carbon.[73] The Federal Laboratories conducted a study of emissions reductions associated with carbon permit costs of $25 and $50 per metric ton of carbon.

The results of many of these analyses are presented in graphic form below. The charts below show values in $2004/metric ton carbon. Charts showing the values in $2004/ton CO_2 are included in the Appendix. The first chart presents the estimates for the year 2010 for analyses that examine reductions to near 1990 levels.

Figure 1: Cost estimates for 2010 – reductions to near 1990 levels



The next chart presents the estimates for the year 2010 for analyses that examine reductions to near 2000 levels.

[72] Burtraw et. al., *The Effect of Allowance Allocation on the Cost of Carbon Emission Trading*, Resources for the Future, August, 2001. Available at http://www.rff.org/rff/Documents/RFF-DP-01-30.pdf

[73] Smith and Bernstein, *Impacts of Implementing a Carbon Cap with a Safety Valve on Allowance Prices*, Charles River Associates, January, 2004. Available at http://www.cpc-inc.org/library/files/20_smithjan04.pdf

Figure 2: Cost estimates for 2010 – reductions to 2000 levels

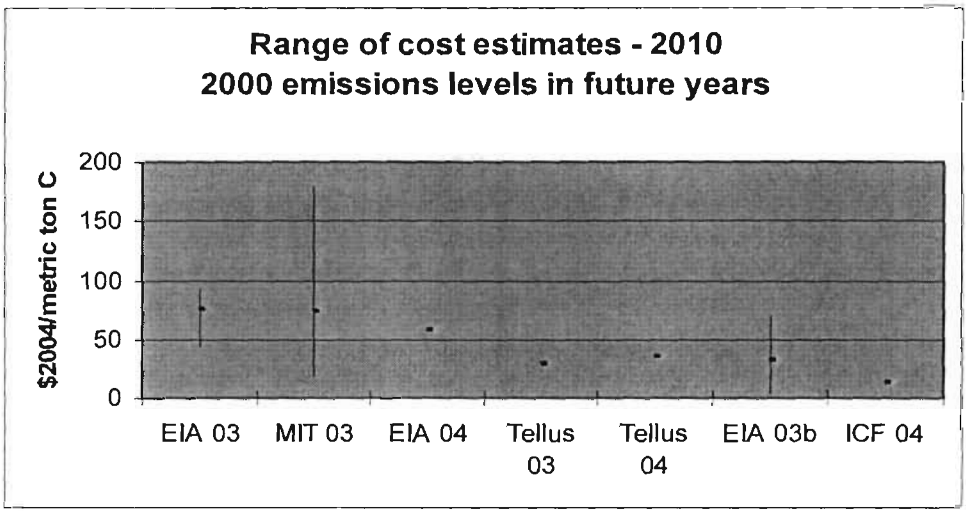
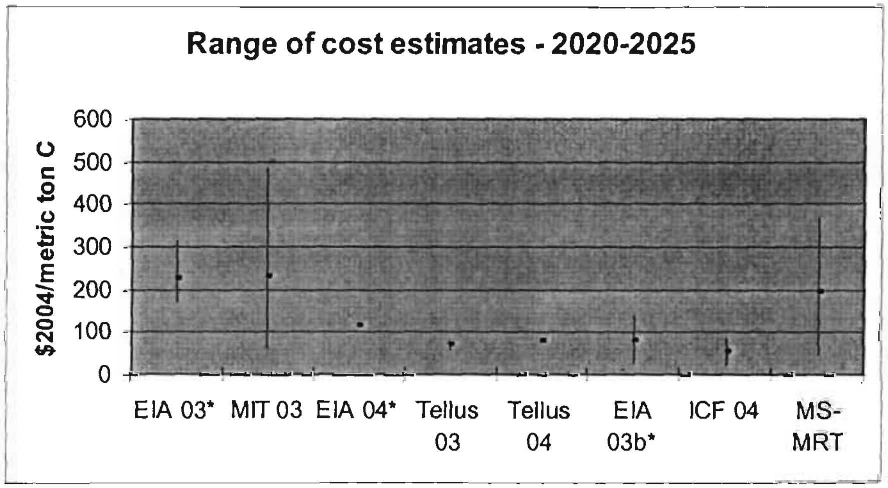


Figure 3 presents estimates for the years 2020-2025 for all emission reduction targets.

Figure 3: Cost estimates for 2020-2025 – all reduction targets



7.4 Other sources of information

Other sources of information can be useful in assessing the potential costs of carbon policies and determining how to evaluate risk associated with possible regulatory scenarios.

National Commission on Energy Policy: A bipartisan group of energy experts from industry, government, labor, academia, and environmental and consumer groups released a consensus strategy, more than two years in the making, to address major long-term U.S. energy challenges. Their report recommends mandatory economy-wide tradeable permits program to limit GHG. Costs would be capped at $7/metric ton of CO_2 equivalent reduction in 2010 with the cap rising 5 percent annually.[74] The National Commission recommendations are the basis of a legislative proposal under consideration in Spring 2005.

Innovest Strategic Value Advisors study for WWF: This study looks at relative costs of different strategies to reduce carbon emission from a portfolio, including: fuel switching, refiring, refurbishment, retiring coal and replacing it with gas combined cycle generation. The study assesses different carbon "price points" from 4 Euros to 30 Euros, based on several studies. Based on a review of carbon scenarios in different regions, the report identifies three common carbon price scenarios: $4-5 per ton carbon, $10-15 per ton carbon (for the period 2007/8 and corresponding roughly to an 8 percent reduction from 2002 emissions levels for specific utilities), and $20-25 per ton carbon (corresponding to a scenario for U.S. utilities where cumulative abatement in 2012 is 23 percent below 2002 emissions levels).[75]

Researchers at the Lawrence Berkeley National Laboratories: LBL researchers provided an overview of various carbon regulation scenarios for DOE.[76] The purpose of the analysis was to provide input to the Office of Energy Efficiency and Renewable Energy (EERE) and the Office of Fossil Energy (FE) in their exploration of options for evaluating the benefits of their R&D programs under an array of alternative futures. This analysis compares two alternative scenarios being considered by EERE and FE staff—carbon cap-and-trade and high fuel prices—to other scenarios used by energy analysts and utility planners. A Scenarios Working Group has proposed to EERE and FE staff the application of an initial set of three scenarios for use in the Working Group's upcoming analyses: (1) a *Reference Case Scenario*, (2) a *High Fuel Price Scenario*, which includes heightened natural gas and oil prices, and (3) a *Carbon Cap-and-Trade Scenario*. The immediate goal is to use these scenarios to conduct a pilot analysis of the benefits of EERE and FE R&D efforts.

The researchers reviewed several recent studies of carbon policy scenarios. The Working Group's *Carbon Cap-&-Trade Scenario* is found to be less aggressive than many Kyoto-style targets that have been analyzed, and similar in magnitude to the proposed Climate Stewardship Act. The proposed scenario is more aggressive than some other scenarios found in the literature, however, ignores carbon banking and offsets, and does not allow the use of nuclear power to expand. The researchers were "somewhat concerned that the stringency of the proposed carbon regulation scenario in the 2010 to 2025 period will lead to a particularly high estimated cost of carbon emissions reduction."

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[74] National Commission on Energy Policy, *Ending the Energy Stalemate*, December 2004, pages 19-29.

[75] Innovest Strategic Value Advisors; "Power Switch: Impacts of Climate Change on the Global Power Sector;" WWF International; November 2003

[76] Wiser and Bolinger; An Overview of Alternative Fossil Fuel Price and Carbon Regulation Scenarios Prepared for the Office of Planning, Budget, and Analysis; Assistant Secretary for Energy Efficiency and Renewable Energy; U.S. Department of Energy; Ernest Orlando Lawrence Berkeley National Laboratory; 1 Cyclotron Road, MS 90R4000, Berkeley CA 94720-8136; October 2004. Available at http://eetd.lbl.gov/ea/ems/reports/56403.pdf

Canada: Canada has taken action on climate change. The Canadian government recently developed a plan for the country to reach its target under the Kyoto Protocol.[77, 78] The government has established a "safety valve" at $12/metric ton of CO_2.[79] Some limited carbon emissions trading has taken place in Canada. For example, Suncor agreed to buy 100,000 tonnes of CO_2 reductions from Niagara Mohawk with an option to buy an additional 10 million tonnes of emission reductions over 10 years. The purchase was valued at $6 million U.S.

New Brunswick Power is currently assuming that the Canadian Government's Kyoto compliance policy will result in a cap and trade system, and that the costs of allowances will be $10/metric ton carbon for the first compliance period of 2008-2012, and $15/metric ton carbon for the second compliance period of 2013 and beyond. Both of these are assumed to escalate at 2 percent per year. Environment Canada indicates that $10/metric ton carbon is a reasonable assumption based on international studies, price expectations from international companies, and current international permit trades.[80]

7.5 Factors that affect projections of carbon cost

Results from these studies highlight certain factors that affect projections of carbon emissions reduction costs. While the studies cannot predict exactly what carbon emissions reduction costs will be, they provide insight into whether the factors increase or decrease expected costs, and to the relationships among different factors. The discussion in this report is qualitative, and not intended as a detailed examination of modeling results and capabilities. [81]

Not surprisingly, two of the most important factors affecting estimates of carbon cost are projected emissions levels in the absence of a policy, and emission reduction targets. In general, higher emissions growth in the base case will result in higher estimates of the costs to achieve emissions reductions from that base case. Similarly, aggressive emissions reductions scenarios result in higher cost estimates than scenarios with more lenient reduction requirements. Another important factor is the assumed rate of growth of low emissions technology. Scenarios that reflect aggressive energy efficiency investment, higher penetration of renewables, and technology innovation produce lower

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[77] According to *Point Carbon*, "the core of the newly designed plan is a $1 billion (630 million) fund through which the Canadian Government will purchase emissions reductions. This will primarily be through sponsoring domestic emissions reduction projects, but could also be used to purchase emissions reductions from international projects using Canadian technology. This fund is estimated to reduce emissions by a total of 100 Mt CO_2e."

[78] http://www.pointcarbon.com/article.php?articleID=6195&categoryID=147

[79] National Commission on Energy Policy, *Ending the Energy Stalemate*, December 2004, page 27.

[80] http://www.climatechange.gc.ca/english/publications/canadascontribution/concluded.html.

[81] Meta-analyses do exist. See, *e.g.*, Carolyn Fischer and Richard D. Morgenstern, *Carbon Abatement Costs: Why the Wide Range of Estimates?* Resources for the Future, September, 2003. Available at http://www.rff.org/Documents/RFF-DP-03-42.pdf

estimates of future carbon emissions reduction costs than those that examine high growth scenarios with little technological innovation.[82]

Other factors that affect carbon costs include geographic scope of trading and flexibility mechanisms (including banking and offsets). Various studies have looked at scenarios that involve global trading of allowances or permits, trading only among Annex B parties, trading only among OECD members, or no trading at all. As we see in Table 7, which shows results from one study, carbon regulation costs decrease with increased global participation. When global competition is not allowed, different regions see different carbon trading prices. Annex 1 trading lowers permit prices for most all Annex 1 regions. The inclusion of non-annex 1 countries, or global trading, further lowers prices for Annex 1 regions, but raises permit and energy prices for non-annex 1 regions. Increased trade generally helps industrial countries, but can have a negative impact on developing countries as terms of trade worsen due to higher energy costs in industrialized nations.[83]

Table 7: Carbon policy has a large impact on carbon regulation costs.

Policy Assumption	$/Metric ton Carbon (1990$)
Global Trading Allowed	17
Annex 1 Trading allowed	57
No trading between countries	127

Assumptions here are from the Rice 98 Model.[84]

7.6 Forecast of carbon allowance prices

Synapse has prepared a forecast of carbon allowance prices that attempts to reflect the information presented in previous sections regarding trading prices under existing GHG regimes as well as modeling results. This forecast, presented in Table 8 and graphed in Figure 4, should not be interpreted as a relatively certain price forecast for CO_2 allowances. Rather, it is intended to be a reasonable forecast of CO_2 prices for planning purposes based on information available today. Despite the uncertainty, we know that zero is the *wrong* value.

[82] While these strategies are not the focus of this paper, the effect of these strategies in reducing costs associated with a carbon constraint clearly have implications for corporate and government strategies on carbon emission reduction.

[83] Wiser, Ryan and Mark Bolinger, *An Overview of Alternative Fossil Fuel Price and Carbon Regulation Scenarios,* Lawrence Berkeley National Laboratory, October 2004.

[84] William Nordhaus and Joseph Boyer, "Requiem for Kyoto: An Economic Analysis," *The Energy Journal*, 1999.

markets where such trading has been established. The figure of $25 per ton of CO_2 is a reasonable expectation for the year 2025 assuming that the target emission level for that year is in the neighborhood of year 2000 emissions. It is somewhat higher than the prices from scenarios that include factors such as a high degree of flexibility in compliance options or aggressive policies to promote clean energy development. It is lower than the prices from scenarios that include factors such as strictly limited flexibility, lack of complementary clean energy policies, or high baseline emissions growth.

8. Conclusion

The earth's climate is strongly influenced by concentrations of greenhouse gases in the atmosphere. International scientific consensus, expressed in the Third Assessment Report of the Intergovernmental Panel on Climate Change and in countless peer-reviewed scientific studies and reports, is that the climate system is already being and will continue to be disrupted due to anthropogenic emissions of greenhouse gases. Scientists expect increasing atmospheric concentrations of greenhouse gases to cause temperature increases of 1.4 – 5.8 degrees C by 2100, the fastest rate of change since end of the last ice age. Such global warming is expected to cause a wide range of climate impacts including changes in precipitation patterns, increased climate variability, melting of glaciers, ice shelves and permafrost, and rising sea levels. Some of these changes have already been observed and documented in a growing body of scientific literature. All countries will experience social and economic consequences, with disproportionate negative impacts on those countries least able to adapt.

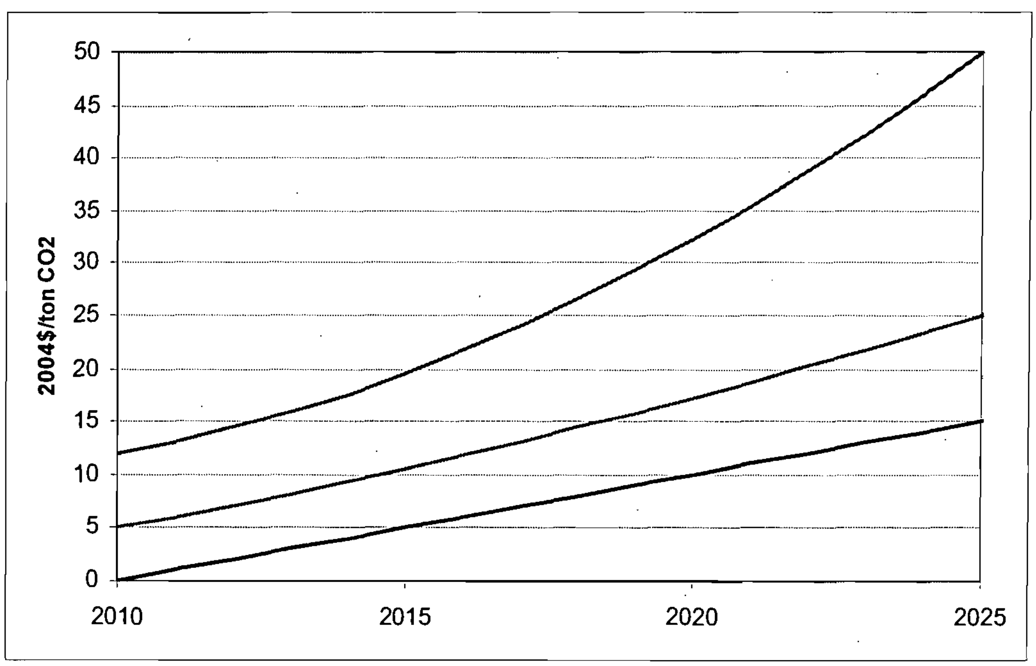
The prospect of Global Warming and changing climate has spurred international efforts to work towards a sustainable level of greenhouse gas emissions. These international efforts are embodied in the United Nations Framework Convention on Climate Change. The Kyoto Protocol, a supplement to the UNFCCC, establishes legally binding limits on the greenhouse gas emissions by industrialized nations and by economies in transition.

The United States, which is the single largest contributor to global emissions of greenhouse gases, remains one of a very few industrialized nations that have not signed onto the Kyoto Protocol. Nevertheless, individual states, regional organizations, corporate shareholders and corporations themselves are making serious efforts and taking significant steps towards reducing greenhouse gas emissions in the United States. Efforts to pass federal legislation addressing carbon emissions, though not yet successful, have gained ground in recent years. These developments, combined with the growing scientific certainty related to climate change, mean that establishing federal policy requiring greenhouse gas emission reductions is just a matter of time. The question is not whether the United States will develop a national policy addressing climate change, but when and how, and how much additional damage will have been incurred by the process of delay. The electric sector will be a key component of any regulatory or legislative approach to reducing greenhouse gas emissions both because of this sector's contribution to national emissions and the comparative ease of controlling emissions from large point sources. While the future costs of compliance are subject to uncertainty, they are real and will be mandatory within the lifetime of existing electric industry capital stock.

Table 8: Forecast of Carbon Dioxide Allowance Prices (2004$)

Year	Low	Mid	High
2010	0.0	5.0	12.0
2011	1.0	6.0	13.1
2012	2.0	7.1	14.4
2013	3.0	8.2	15.9
2014	4.0	9.4	17.6
2015	5.0	10.6	19.6
2016	6.0	11.8	21.7
2017	7.0	13.1	24.0
2018	8.0	14.4	26.5
2019	9.0	15.8	29.3
2020	10.0	17.2	32.2
2021	11.0	18.7	35.4
2022	12.0	20.2	38.7
2023	13.0	21.8	42.3
2024	14.0	23.4	46.0
2025	15.0	25.0	50.0
Levelized	6.1	12.4	23.9

Figure 4. Carbon Dioxide Allowance Price Forecast



The mid-case forecast is for $5 per ton of CO_2 in 2010 increasing to $25 per ton of CO_2 in 2025. The 2010 price is lower than recent actual trading prices of carbon dioxide in

In this scientific, policy and economic context, it is imprudent for decision-makers in the electric sector to ignore the cost of future carbon emissions reductions or to treat future carbon emissions reductions merely as a sensitivity case. Treating carbon emissions as zero cost could result in investments that prove quite uneconomic in the future. Long term resource planning by utility and non-utility owners of electric generation must account for the cost of mitigating greenhouse gas emissions, particularly carbon dioxide. For example, decisions about a company's resource portfolio, including building new power plants, reducing other pollutants or installing pollution controls, avoided costs for efficiency or renewables, and retirement of existing power plants all can be more sophisticated and more efficient with appropriate consideration of future costs of carbon emissions mitigation.

Regulatory uncertainty associated with climate change clearly presents a planning conundrum, but this does not justify proceeding as if no costs will be associated with carbon emissions in the future. The challenge, as with any unknown future cost driver, is to forecast a reasonable range of costs based on analysis of the information available. This report identifies many sources of information that can form the basis of reasonable assumptions about the likely costs of meeting future carbon emissions reduction requirements.

Available sources include market transactions, values used in utility planning, and modeling analyses. Carbon markets associated with implementation of the Kyoto Protocol as well as voluntary emissions reductions have emerged, with carbon trading in January 2005 at a range of \$30-63/metric ton carbon (\$8-17 per ton CO_2). Values in electric company resource planning range from \$4-44/metric ton carbon (\$1-12 per ton CO_2); and the California Public Utilities Commission has directed utilities to include carbon at a value between \$30-93/metric ton carbon (\$8-25 per ton CO_2) in their long term resource planning. Numerous studies estimate the possible costs of carbon allowances under various policy scenarios, many of which are identified in this report. Projections of carbon costs for the year 2010 range from \$4/metric ton carbon to \$401/metric ton carbon (\$1 and \$99/ton CO_2) under different policy scenarios. Projections for carbon costs for the period 2020-2025 range from \$27/metric ton carbon to \$486/metric ton carbon (\$7 and \$120/ ton CO_2). Modeling results are sensitive to several factors including (1) the emissions reduction target; (2) projections of future electrical load and emissions in the absence of a greenhouse gas reduction target; (3) geographic scope of trading; and (4) flexibility mechanisms such as offsets and allowance banking. All of these sources of information are explained in more detail in the report.

The sensitivity of the carbon price levels to the emissions reduction target can be seen by grouping the results for 2010 into two groups based upon the level of the target. For studies that analyze the costs associated with returning to the emissions levels of the year 2000 by the year 2010 or thereabouts, costs in 2010 are projected to be between \$4/metric ton carbon and \$179/metric ton carbon (\$1/ton CO_2 and \$44/ton CO_2). Studies that analyze the costs associated with a somewhat more aggressive goal of reducing emissions to near 1990 levels reveal costs in 2010 between \$4/metric ton carbon and \$401/metric ton carbon (\$1/ton CO_2 and \$99/ton CO_2).

Appendix: Conversion and Values in \$2004/ton CO2

A-1: Conversions

Original dollars were converted using Gross Domestic Product Implicit Price Deflator.

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
0.754	0.780	0.798	0.817	0.834	0.851	0.867	0.882	0.891	0.904	0.924	0.946	0.962	0.979

The following conversions were also used:

1 metric ton = 1.102 short tons

1 short ton = 0.907 metric tons

There are 12 g of carbon in 44 g of carbon dioxide

These sources of information permit a broad assessment of potential carbon allowance prices. Indeed, incorporating reasoned assessment of future costs associated with greenhouse gas emissions is likely to be an increasingly important component of corporate success.

Figure A-1: Cost estimates for 2010 – reductions to near 1990 levels

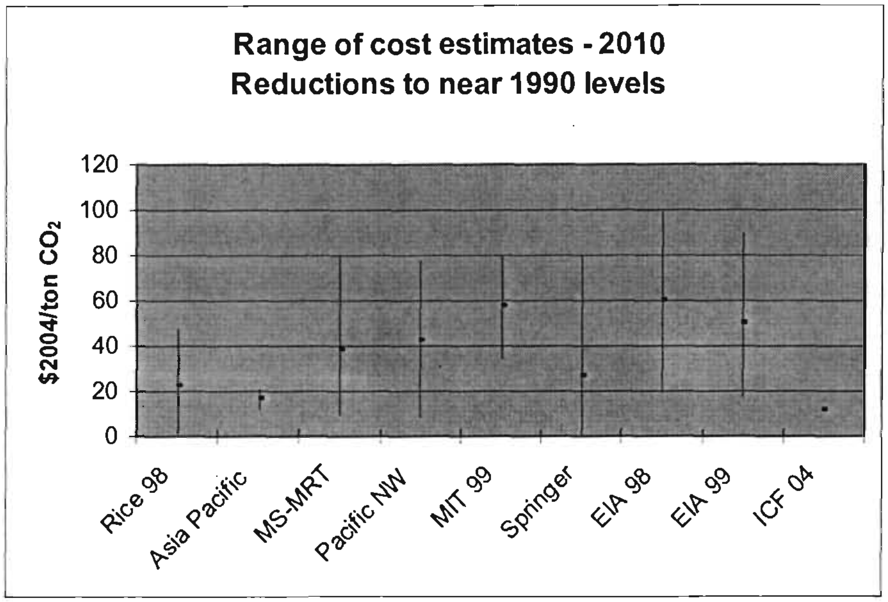
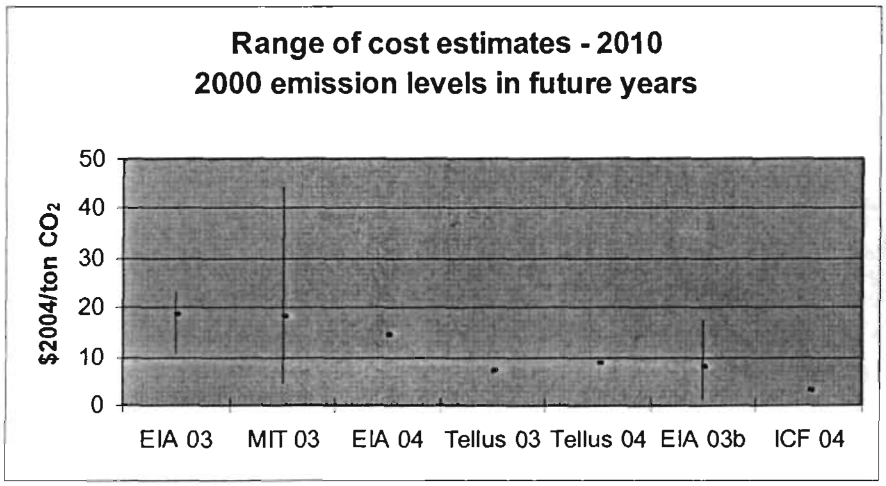


Figure A-2: Cost estimates for 2010 – reductions to 2000 levels



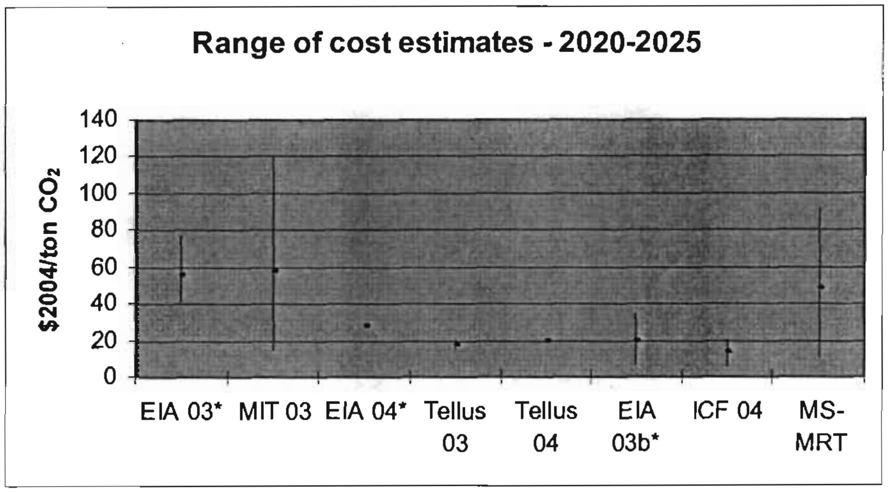
A-2: Allowance cost estimates in $2004/ton CO_2

Table A-1: Estimates of U.S. Allowance Costs ($US2004/ton CO_2)

Study	2010 Emissions Goal	2010 Allowance Price Range	2020-2025 Allowance Price Range**
		$2004/ton CO_2	$2004/ton CO_2
SEMF -Rice 98	7% below 1990 levels 2008-2012	1-47	-
SEMF -Asia Pacific	7% below 1990 levels 2008-2012	12-21	-
SEMF -MS MRT	7% below 1990 levels 2008-2012	9-80	10-91
SEMF - Pacific Northwest	7% below 1990 levels 2008-2012	8-77	-
SEMF -MIT Emissions	7% below 1990 levels 2008-2012	34-80	-
EIA '98	24% above 1990 levels to 7% below 1990 levels 2008-2012	19-99	-
EIA '99	24% above 1990 levels to 7% below 1990 levels 2008-2012	18-90	-
ICF '04	1990 levels in 2010	12	19-21
Springer summary of 25 models*	Kyoto targets in 2010	1-80	-
EIA '03	2000 levels 2010, 1990 levels in 2016	11-23	167-314
EIA '04	2000 levels 2010 and beyond	14	28
MIT '03	2000 levels 2010 and beyond	4-44	15-120
Tellus '03	2000 levels 2010, 1990 levels 2016	7-8	14-21
Tellus '04	2000 levels 2010 and beyond	9	20
CRA	2000 levels starting 2010, with safety valve	4	4-7
EIA '03b	2001 emissions in 2013	1-8	7-35
ICF '04b	2000 levels in 2010	3	5
RFF***	6% reduction from BAU scenario, starting 2008	6-10	-

* *Springer summary allowance prices are global rather than U.S.*
** *MIT '03, MS MRT, CRA, Tellus, results for 2020; EIA '03, EIA '03b, and '04 results for 2025..*
*** *RFF results for 2012. Study focuses relative costs of allocation methods.*

Figure A-3: Cost estimates for 2020-2025 – all emission reduction targets



SIERRA CLUB
FOUNDED 1892

Email to Al and Tom Davis

October 9, 2006

Via Electronic Mail: mike.halpin@dep.state.fl.us
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RE: Comments on Intent to Approve PSD Major Modification to Add New Unit 3 at Seminole Electric Cooperative, Inc.

Dear Ms. Vielhauer, Mr. Halpin and Mr. Koerner,

We represent the Sierra Club and are writing to submit comments on its behalf regarding the Florida Department of Environmental Protection (FDEP) draft permit authorizing Seminole Electric Cooperative, Inc. to construct a new 750 MW unit and associated sources at the existing Seminole power plant, PSD-FL-375, Project No., 1070025-005-AC, hereafter referred to as Seminole 3. The proposed issuance of the permit to allow construction of the 750 MW unit is unlawful for many reasons. Because the draft permit suffers from serious defects, it must be significantly revised and FDEP must require a new public notice of the revised draft permit.

We appreciate your consideration of our views and FDEP's efforts to make documents regarding this action available to interested parties. Please notify us promptly of any subsequent action on this draft permit, including issuance of any response to comments, a new draft permit, and/or a final permit.

I. THE SIERRA CLUB AND ITS MEMBERS WILL BE ADVERSELY AFFECTED BY THE ISSUANCE OF THE DRAFT PERMIT.

The Seminole 3 project will pose significant threat to public health and the environment. The project would expand the existing Seminole facility, Units 1 and 2, with a third 750 megawatt unit, referred to herein as Seminole 3. It will emit a large amount of pollutants known to pose a threat to the public health and the environment, including sulfuric acid mist, mercury, nitrogen oxides, sulfur dioxide, particulate matter, volatile organic compounds, and carbon monoxide. It will also emit large amounts of carbon dioxide, which contributes to global warming. These three units could operate for upwards of 40 years.

The Sierra Club was founded in 1892 and is the nation's oldest grass-roots environmental organization. The Sierra Club has more than 750,000 members nationwide, including over 33,000 members in Florida, with 105 and 520 members in Putnam and St. Johns Counties respectively. The Sierra Club is dedicated to the protection and preservation of the natural and human environment, including protecting public health. The Sierra Club's purpose is to explore, enjoy and protect the wild places of the earth; to practice and promote the responsible use of the earth's ecosystems and resources; and to educate and enlist humanity to protect and restore the quality of the natural and human environments. One of the Sierra Club's national priorities is the Smart Energy Solutions Conservation Initiative, which tackles the pressing problems of global warming, air pollution, and our national dependence on dirty, non-renewable energy sources such as nuclear power, oil and coal.

The Sierra Club has members in Florida whose recreational, aesthetic, business and/or environmental interests have been, are being, and will be, adversely affected by Seminole 3. Members of the Sierra Club use and enjoy the outdoors throughout the state of Florida, including areas impacted from pollution from Seminole 3, for outdoor recreation and scientific study of various kinds, including nature study, falcon-watching, photography, backpacking, camping, solitude, and a variety of other activities. In addition, Sierra Club members use the Okefenokee, Wolf Island, and Chassahowitzka National Wilderness Areas ("NWA") for outdoor recreation and scientific study of various kinds. The Sierra Club submits these comments on behalf of itself and its members.

II. FDEP MUST DENY THE PERMIT DUE TO SEMINOLE'S FAILURE TO PERFORM ADEQUATE BACT ANALYSES.

The PSD construction permit program reflects a delicate balance between allowing economic development and protecting public health and the environment. Sources may obtain permits to expand their operations and/or construct new polluting facilities only if they satisfy two overarching requirements. First, they must demonstrate that their emissions will not cause unacceptable impacts to air quality. 42 U.S.C. § 7475(a)(3); § 643.075.3, 62 F.A.C. § 62-212.400(5). Second, even if they satisfy that prerequisite, they must also reduce their emissions by employing the "best available control technology" (BACT). 42 U.S.C. § 7475(a)(4); 62 F.A.C. § 62-212.400(10)(b).

A. Failure to Conduct Adequate, Five-Step BACT Analyses

Florida regulations define the "Best Available Control Technology" or "BACT" as:

> (a) An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account:
>
> 1. Energy, environmental and economic impacts, and other costs;
>
> 2. All scientific, engineering, and technical material and other information available to the Department; and
> 3. The emission limiting standards or BACT determinations of Florida and any other state determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

62 F.A.C. 62-210.200(39). Furthermore,

It should be noted that possible grounds for overturning a BACT decision include an inappropriate review (BACT procedures not correctly followed), an incomplete review (BACT decisions not correctly justified), or a review based on false or misleading information. See Letter from Robert B. Miller, Chief, Permits and Grants Section, EPA Region 5 to Lynn Fiedler, Supervisor, Permit Section, Air Quality Division, Michigan Department of Environmental Quality (Oct. 6, 1999).[1]

EPA's Draft 1990 New Source Review Workshop Manual details the necessary process for a "top down" BACT review. This five-step process must be conducted to ensure that a valid BACT determination has been made:

- STEP 1: Identify all control technologies. This list must be comprehensive and include all "Lowest Achievable Emission Rates" ("LAER")

- STEP 2: Eliminate technically infeasible options. A demonstration of technical infeasibility should be clearly documented and must show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.

[1] Available at www.epa.gov/Region7/programs/artd/air/nsr/nsrmemos/cadillac.pdf.

- STEP 3: Rank remaining control technologies by control effectiveness. This must include:
  - o control effectiveness (percent pollutant removed);
  - o expected emission rate (tons per year);
  - o expected emission reduction (tons per year);
  - o energy impacts (Btu/kWh);
  - o environmental impacts (other media and the emissions of toxic and hazardous air emissions); and
  - o economic impacts (total cost effectiveness, incremental cost effectiveness)

- STEP 4: Evaluate most effective controls and document results. This must include a case-by-case consideration of energy, environmental, and economic impacts. If top option is not selected as BACT, evaluate next most effective control option.

- STEP 5: Select most effective option not rejected as BACT

The U.S. EPA Environmental Appeals Board (EAB) has consistently upheld this five step process. As outlined above, first, the applicant must identify all "available" control options. Second, the applicant may eliminate "technically infeasible" options by determining for each technology whether it has been installed and operated successfully elsewhere, and if not, whether it is "available" and "applicable." *In re Maui Electric Co.*, 8 E.A.D. 1, 5-6 (EAB 1998). "Available" means commercially available. If "available," the technology is "applicable" if it can be installed and operated on the source in question. *Id.* Applicants can eliminate technologies that are not demonstrated and either not available or not applicable. Third, the applicant must list all options identified in step one that were not eliminated in step two in order of stringency. Fourth, the applicant must consider site specific collateral impacts to energy, environment, and economy. *In re Kawaihae Cogeneration*, 7 E.A.D. 107, 117 (EAB 1997); *In re World Color Press, Inc.*, 3 E.A.D. 474, 478 (Adm'r 1990) ("[T]he collateral impacts clause focuses upon specific local impacts which constrain a particular source from using the most effective control technology.") After considering collateral impacts, the top alternative in step three is either confirmed as appropriate or is determined to be inappropriate. Finally, the applicant selects as BACT the most effective control alternative not eliminated in step four. *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 202 (EAB 2000)(quoting *In re Masonite Corporation*, 5 E.A.D. 551, 564 (EAB 1994)).

Said another way:

> [T]he top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent—or "top"—alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

NSR Manual at B-2.

The BACT definition and the NSR Manual make clear that potential pollution control technologies should be assessed on their relative effects not only in reducing emissions of the target pollutant, but on all other pollutant emissions. See NSR Manual at B.46-50.

As described below, Seminole's BACT analysis is unlawful and clearly erroneous. EPA guidance is clear that the permitting agency and the applicant are under an ongoing duty until the date of final permit issuance to update the BACT analysis as new information becomes available. Because these comments indicate there are numerous other permits and emission rates that are being achieved at existing coal-burning power plants—and not yet considered as part of the Seminole BACT analysis—its BACT analysis must be significantly revised and updated.

B. The CO And VOC BACT Analysis Are Flawed

The Draft Permit proposes a VOC BACT limit of 0.0034 lb/MMBtu and CO BACT limits of 0.13 lb/MMBtu (coal only) and 0.15 lb/MMBtu on a 30-day rolling average for all fuels. Draft Permit at 8. The CO and VOC BACT analyses share the same flaws, they are not based on the above-described five-step process, but rather dismiss a feasible technology and pluck a value out of the middle of the range of a list of recently permitted projects. This is contrary to definition of BACT. They further, in part, fail to specify an averaging time, making them unenforceable as a practical matter. See NSR Manual at B.56.

1. BACT Analysis Improperly Dismissed A Feasible Technology

The CO and VOC BACT analyses argue that there are no feasible control technologies. Ap., p. 51. The FDEP BACT analyses diverge, concluding that thermal oxidization is feasible because it is in use at a cement kiln in Texas. Technical Evaluation at 13. Petitioners also note that thermal oxidation is widely used in ethanol plants, refineries, and other sources to control VOC and CO emissions. However, FDEP did not require this technology for Seminole Unit 3 because FDEP could find no evidence that thermal oxidation had been used in this application. This is the wrong standard. The refusal to use a technology on a similar source because it has never been used on this source before is contrary to the legislative history of the Clean Air Act. BACT is suppose to be technology forcing. Refusing to require an applicable technology just because it has not yet been required is not technology forcing.

Similarly, the NSR Manual notes that "[o]pportunities for technology transfer lie where a control technology has been applied at source categories other than the source under consideration." NSR Manual at B.11. Elsewhere, the NSR Manual notes:

Technology transfer must be considered in identifying control options. The fact that a control option has never been applied to process emission units similar or identical to that proposed does not mean it can be ignored in the BACT analysis if the otential for its application exists.

NSR Manual at B.16.

Thus, since thermal oxidation is a feasible BACT control technology under step 2 of the top-down process, its control effectiveness or achievable emission limit must be ranked along with other emission limits. Thermal oxidation routinely removes 90% of the CO and 98% of the VOC from similar gas streams. Thus, it is much more efficient than "combustion controls" selected as BACT and is able to achieve emission limits that are at least ten times lower than those picked for Seminole.

Therefore, thermal oxidation should have been picked as BACT for Seminole 3 unless adverse energy, environmental, and economic impacts are documented. NSR Manual at B.6. The Application and Technical Evaluation do not contain a responsive analysis that documents adverse energy, environmental or economic impact and we are not aware of any, based on the widespread use of this technology on a wide range of sources. Rather, thermal oxidataion is summarily dismissed as not feasible (Ap. 51) or never used before on this source. Technical Evaluation at 14. This is contrary to the definition of BACT and the legislative history of the Clean Air Act. Thus, the BACT analysis for CO and VOCs is flawed, should be remanded to the applicant to correct, and the Draft Permit recirculated for public review.

2. BACT Is Not The Middle Of The Pack

The application states that "CO emission limits established as BACT over the last several years range from 0.1 to 0.16 lb/MMBtu, with a median value of 0.15 lb/MMBtu (see Table B-1e)." Ap. at 51. Table B-1e lists seven recent PC boiler projects with CO emission limits ranging from 0.11 to 0.15 lb/MMBtu, thus not supporting the range claimed in the text. The application then concludes that BACT for CO is 0.15 lb/MMBtu because it is "within the range of emission rates recently established as BACT." Ap., Sec. 4.3.3.3, p. 52.

The Technical Evaluation expands the list of CO limits to include 14 plants, reporting a range of 0.10 to 0.20 lb/MMBtu. Technical Evaluation at 14. The FDEP then states that it "will accept the applicant's proposed BACT limit at 0.13 lb/MMBtu while firing coal,as it is in the lower range of recent BACT Determination." Ibid. The FDEP further accepts the 0.15 lb/MMBtu 30-day average because a value established by CEMS is a little higher than a value established by a stack test. Ibid. However, most all of the limits in FDEP's table are established by CEMS, including the lowest reported values, thus undercutting this argument.

Further, the FDEP CEMS argument, in essence, accepts the applicant's rationale that the limit meets BACT because it is within the range of recently permitted CO limits.

As described above, Florida's regulations require the Dept. to consider recent BACT determinations in Florida and other States. The Dept. clearly reviewed (and weighed) this information in making its determination. Florida's regulations do not require selection of the lowest emissions standard, (For PSD preconstruction review)

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However, the FDEP's own summary of CO limits refutes this conclusion. The FDEP summary table shows three permit limits based on short term averages and CEMS testing that are lower than the 0.15 lb/MMBtu 30-day average measured by CEMS and proposed for Seminole 3: PSC Colorado (0.13 lb/MMBtu 8-hr average); Longview, WV (0.11 lb/MMBtu 3-hour average); and Thoroughbred, KY (0.10 lb/MMBtu 30-day rolling average). Ibid. All three of these lower limits are confirmed by CEMS testing.

Same

The Sierra Club appears to request that the Dept. establish the Lowest Achievable Emissions Rate (LAER). However, this procedure is only required for projects located in areas that are out of attainment with an Ambient Air Quality Std. This is not the case for Seminole project.

Similar arguments are made for VOCs. The application selects 0.0036 lb/MMBtu as BACT because it is "within the range of emission rates established for similar sources." (0.0024 to 0.01). Ap. at 52. The FDEP disagreed, noting that two-thirds of the applicant's cited VOC limits were lower than the proposed limit and that the FGD and WESP would remove VOCs. Thus, FDEP lowered the applicant's VOC BACT limit from 0.0036 to 0.0034 lb/MMBtu. Technical Evaluation at 15. While this is a move in the right direction, it does not go far enough. Two out of the 14 values tabulated by the FDEP are lower than the proposed VOC limit of 0.0034 lb/MMBtu – 0.0024 lb/MMBtu and 0.0027 lb/MMBtu. We are aware of other, lower VOC BACT limits including: Trimble, KY (0.0032 lb/MMBtu), Bull Mountain, MT (0.0030 lb/MMBtu) and Springerville, AZ (0.0033 lb/MMBtu).

This approach is fundamentally flawed and should be remanded for a new BACT determination.

First, picking a CO and VOC limit just because they are in the middle of the pack, as here, is contrary to the definition of BACT, which defines BACT as an emission limit based on the maximum degree of reduction.

Second, the Application and Technical Evaluation are silent as to why these lower CO and VOC limits do not establish BACT for Seminole 3. This is also contrary to the definition of BACT which requires that the lowest emission limit be selected unless adverse energy, environmental, and economic impacts are documented. NSR Manual at B.6.

Not required for this project

Third, the universe of sources that one must consider in making a BACT determination is much broader than just recently permitted sources. Other information sources must be considered to assure that the lowest achievable emission limit is specified as BACT. These other sources include control technology vendors, technical literature, and foreign experience. NSR Manual at B.11. Further, 62 FAC 62-212.400(10)(b) expressely notes that the BACT determination shall be based on "2. All scientific, engineering, and technical material and other information available to the Department." A much wider range of information is available to the Department than just recently permitted projects.

Fourth, we note that Seminole 3 will use a supercritical boiler. Ap. at 1. A supercritical boiler is more efficient than a subcritical boiler, or the so-called standard PC

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boiler, and thus is able to achieve lower emissions, including lower CO and VOC.[2] Most of the permitted CO and VOC limits relied on by the applicant and FDEP are based on the less efficiency subcritical boiler technology. The application admits that the "boiler will be designed and operated for high-combustion efficiency, which will inherently minimize the production of CO." Ap. at 51. Thus, Unit 3 should be able to meet the lowest reported CO and VOC limits and likely could meet an even lower CO and VOC limits than previously permitted and relied on here. The technology forcing nature of BACT requires that FDEP lower the VOC and CO BACT limits to address the higher efficiency and thus lower emissions that can be achieved with a supercritical boiler.

Thus, the BACT analysis for CO and VOCs is flawed, should be remanded to the applicant to correct, and the Draft Permit recirculated for public review.

This is the 2nd reference
Did the SC provide comment
on this project?

C. The Proposed Fluoride Limit Does Not Reflect BACT

The Draft Permit proposes a "HF" BACT limit of 0.00023 lb/MMBtu (1.72 lb/hr equivalent. Draft Permit at 8. This limit was selected by the applicant using the same flawed process documented above for VOC and CO. The applicant listed the limits recently permitted at seven similar facilities. Ap., Table B-1g. The applicant then proposes 0.00023 lb/MMBtu as BACT because it "is in the lower range of recent BACT determination…" Ap. at 53. The FDEP adopts this approach wholesale, adding nothing to the debate. Technical Evaluation at 8.

As discussed supra, BACT is not an emission limit that is within the lower end of the range of permitted levels. The search must be more far reaching than just permitted levels. Further, the value selected as BACT is not the lowest permitted value. The applicant's summary identifies two lower fluoride limits: Longview, WV (0.0001 lb/MMBtu) and Comanche, CO (0.0001 lb/MMBtu). The Application and Technical Evaluation contain no justification for not selecting the two lower limits as BACT for Seminole 3.

D. The Proposed Particulate Matter Limit Does Not Reflect BACT

Particulate matter ("PM") is the "generic term for a broad class of chemically and physically diverse substances that exist as discrete particles (liquid droplets or solids) over a wide range of sizes." 62 Fed. Reg. 38,652, 38,653 (July 18, 1997). Particulate matter with an aerodynamic diameter of ten micrometers or less is referred to as "PM10".

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[2] E.S. Sadlon, Alstom, Application of State-of-the-Art Supercritical Boiler Experience to U.S. Coals – Corrosion Consideration, CoalGen 200; Tim O'Brien and Steve Pieschl, Black & Veatch, Black & Veatch Advanced Supercritical Pulverized Coal Reference Plant, CoalGen 2005; P. Armstrong and others, Design and Operating Experience of Supercritical Pressure Coal Fired Plant.

Id. at 38,653 n.1. PM can be measured in its various forms, including "filterable" particulates, which are captured on a filter, or as "condensable" particulates, which are captured in a condenser or impinger train. See 40 C.F.R. pt. 51, methods 201, 201A and 202.

The draft Seminole permit proposes a filterable PM limit of 0.013 pounds per million BTU. Draft Permit p. 8. There is no limit for condensable PM. The proposed permit is therefore unlawful because a) the draft permit fails to establish a PM limit for filterable PM that represent BACT, and b) it fails to set a BACT limit for Condensable PM.

1. BACT for Filterable PM Should be More Stringent

The Draft Permit contains a PM limit for Unit 3 of 0.013 lb/MMBtu. This purports to be a BACT limit. However, BACT for PM emissions from a coal fired power plant is much lower. In Seminole's application, they noted (but ignored), the following BACT technology and PM emission rates:

Reliant Energy Seward, PA
JEA Northside, FL – PM emission rate = 0.011 lbs/mmBTU (3-hour)

Air Permit Application, Appendix B, p. 1. Seminole's application did not state the PM emission rate for Reliant Energy Seward, PA, which is 0.010 lbs/mmBTU.

Nor did Seminole include the PM emission rates for the Northhampton facility. In 1995, Pennsylvania issued a PSD permit to the Northampton Generating Company with a total PM10 limit of 0.0088 lb/MMBtu. This facility is a 1,146 MMBtu/hr circulating fluidized bed boiler. Compliance testing in February 2001 reported total PM10 emissions of 0.0045 lb/MMBtu. Contrary to the common misconception that the permit limit is for filterable PM only and that the compliance test only included filterable PM, the 0.0088 lb/MMBtu Northampton permit limit and the compliance test include some condensable PM. The Northampton permit requires testing by "Method 5," which refers to Pennsylvania Method 5. Unlike U.S. EPA Method 5, which only tests for filterable particulate matter, Pennsylvania's "Method 5" includes both front half and back half emissions (i.e., both filterable and condensable PM). In response to requests for more information, the Pennsylvania DEQ confirmed that the compliance tests for Northampton included condensable fraction PM in the back half of the sampling train.

Furthermore, EPA recently wrote in comments on the proposed Longview power plant in West Virginia that even more stringent PM limits must be considered in a PM BACT analysis based on recent performance testing at Northampton which indicate an even lower PM rate. See Letter from David Campbell, US EPA to Edward Andrews, WV DEP (undated). According to EPA, based on recent performance testing (for both filterable and condensable), Northampton is achieving a PM limit of 0.0045 lbs/mmBTU.

Seminole also excluded the PM emission limits for the Baldwin facility from its BACT analysis. In 2002, EPA established a BACT limit for PM as follows:

> [A]n emission rate of 0.006 pounds per million BTU based on use of a 99.6% pulse jet baghouse is BACT for particulate matter at Baldwin Units 1 and 2. Monitoring would be via EPA method 5, and triboelectic broken bag monitors.

Haber Declaration at 46. The EPA noted that the BACT analysis was based, in part, on the cost-effectiveness finding from the Public Service Electric & Gas Company's Mercer Unit built in 1994 that included a $38.9 million ESP that is removing 99.8 percent of its PM. Id.

Because Northampton, Baldwin, Reliant Energy, and JEA Northside are achieving lower emission rates, and Seminole has not shown any reason why such lower emission rates cannot be achieved at Seminole 3, the BACT limit for total PM emissions at Seminole must be revised. NSR Manual at B.24 ("[i]n the absence of a showing of differences between the proposed source and previously permitted sources achieving lower emission limits, the permit agency should conclude that the lower emission limit is representative for that control alternative."); Newmont Nevada Energy Investments, Slip Opinion at p. 16 (E.A.B. 2005). This analysis must consider the additional and significant PM reductions associated with using a baghouse, instead of an ESP. Moreover, utilizing a baghouse will significantly reduce mercury emissions.

Seminole claims that fabric filters (baghouses) are not a viable option because Seminole 3 will burn high sulfur coal and there is an unknown long-term reliability of fabric filters when used with high-sulfur coal. Seminole Application at 50. Seminole also claims that there is only one plant burning high sulfur coal that utilizes baghouses. This argument will not allow Seminole to disregard this viable BACT technology for three reasons.

First, Seminole 3 could burn low-sulfur coal. BACT determinations must consider better coal quality as a way to reduce emissions. EPA recognizes that Congress explicitly amended the definition of BACT to ensure clean fuels are considered:

> The phrase 'clean fuels' was added to the definition of BACT in the 1990 Clean Air Act amendments. EPA described the amendment to add 'clean fuels' to the definition of BACT at the time the Act passed, 'as * * * codifying its present practice, which holds that clean fuels are an available means of reducing emissions to be considered along with other approaches to identifying BACT level controls.' EPA policy with regard to BACT has for a long time required that the permit writer examine the inherent cleanliness of the fuel.

Inter-Power of New York, 5 E.A.D. at 134 (emphasis added, internal citations omitted). EPA requires permitting agencies to consider clean fuels in every BACT analysis, as a recognized method of pollution prevention. Knauf, 8 E.A.D. at 136; In re: Old Dominion Electric Cooperative, 3 E.A.D. at 794, n. 39 (EAB 1992) ("BACT analysis should include consideration of cleaner forms of the fuel proposed by the source."); Hibbing Taconite, 2 E.A.D. at 842-843 (remanding a permit because the permitting agency failed to consider burning natural gas as a viable pollution control strategy).

Considered overall balance of control options selected?

Therefore, Seminole is required to consider using cleaner fuels in step one of the top-down BACT process and either establish a PM BACT limit based on the cleanest coal available, or justify its basis for not doing so. Moreover, utilizing lower sulfur coal has multi-pollutant benefits, included but not limited to, lower SOx emissions, lower SAM emissions, lower NOx emissions, and of course, enhanced attractiveness of a fabric filter (due to improved ash properties and lower SO_3 concentrations).

Second, Seminole could implement measures to reduce SO_3 emissions, the root cause problem for baghouses. These include blending an alkali with the coal, alkali injection into the boiler, use of a low conversion SCR catalyst with an SO_2 to SO_3 converstion rate of 0.5% or less, or alkali injection upstream of the baghouse.

Third, Unit 3 could be designed to minimize baghouse fouling by operating the air preheater at temperatures above the acid condensation point and using bags that have been demonstrated to have low failure rates in high sulfur applications, e.g., membrane bags instead of acid-resistant fiberglass.[3]

Fourth, a number of recently permitted high sulfur coal projects will use baghouses including—Longview, WV, Trimble, KY, Oak Creek, WI, and Dallman Unit 4, IL. The latter three projects are under construction with baghouses. This demonstrates that the utility industry and its vendors consider baghouses in high sulfur applications to be commercially available and feasible, requiring that baghouses be evaluated as BACT for Seminole, rather than summarily rejected.

Therefore, Seminole must consider the additional and significant PM reductions associated with using a baghouse, even if that means utilizing a cleaner coal or fabric filters that are more resistant to corrosion.

2. The PM permit must set a BACT limit for condensable PM.

The draft Seminole permit has no limit for condensable PM. See Seminole Draft Permit at 8. EPA has taken the position, for at least ten years, that condensable PM is part of a source's PM emissions and must be considered in a BACT analysis. In a March 31, 1994, letter to the Iowa Department of Natural Resources, EPA responds to a series of questions. The first two are relevant here:

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[3] See, for example, McIlvaine FGD and DeNOx Newsletter, SCR Affected Fabric Filter Operation at Wateree, No. 340, August 2006 and J.A. Robinson, Jr., Experiences from Three Years of SCR Operation, 2006 Environmental Control Conference, May 16-18, 2006.

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Jeb Bush
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Secretary

Iowa DNR: Does the Environmental Protection Agency (EPA) definition for PM-10 include condensable particulate matter (CPM)?

US EPA: Yes, the definition of PM-10 includes CPM.

Iowa DNR: Are the States required to compute PM-10 as the sum of in stack and condensable PM-10?

US EPA: Since CPM is considered PM-10 and, when emitted, can contribute to ambient PM-10 levels, applicants for PSD permits must address CPM if the proposed emission unit is a potential CPM emitter.

Letter from Thompson Pace, OAQPS, EPA to Sean Fitzsimmons, Iowa DNR (Mar. 31, 1994).[4] In a March 30, 2004 memo, Air and Radiation Division Director, Stephen Rothblatt, requested EPA Headquarters to issue a nationwide memo to remind states that they must include a condensable PM BACT limits in coal plant permits. EPA Region 5 has submitted comments on the draft Peabody permit informing IEPA it must include a condensable PM limit. The Wisconsin DNR has proposed a permit for Weston 4 that includes a condensable PM limit.

On September 27, 2006, the Environmental Appeals Board issued a decision in In re: Indeck-Elwood, LLC, PSD Appeal No. 03-04, PSD Permit No. 197035AAJ. In this decision the Board remanded the PSD permit issued by the Illinois EPA to "reconsider whether a PM limitation, including a limitation for condensable particulate matter is appropriate, and if so, to modify the permit accordingly." The Board noted that the U.S. "EPA has previously expressed the position that it is important to account for CPM 'where condensibles constitute a significant fraction of the total PM10 because otherwise, the PM10 impact will be underestimated.'" AES Puerto Rico L.P., 8 E.A.D. 324, 348 (EAB 1999) (citing Letter from Thompson G. Pace, U.S. EPA, to Sean Fitzsimmons, Iowa Department of Natural Resources (Mar. 31, 1994)), aff'd sub nom. Sur Contra La Contaminación v. EPA, 202 F.3d 443 (1st Cir. 2000). In addition, the Board noted that the Illinois had to consider regulating condensable PM because the Illinois EPA had recently issued a permit to Prairie State that set two limits for particulate matter, one stated as filterable PM and another stated as filterable and condensable PM. *Prairie State*, slip op. at 97, 13 E.A.D.

The existence of a similar facility with a lower emissions limit creates an obligation for Seminole (and FDEP) to consider and document whether that same emission level can be achieved at Seminole 3. Other permits for similar facilities have regulated condensable PM and Seminole's final permit must include no less.

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[4] See also, 56 Fed. Reg. 65,433 (Dec. 17, 1991) ("Since CPM emissions form very fine particles in the PM10 size range and are considered PM10 emissions * * **"); 55 Fed. Reg. 14,246 (Apr. 17, 1990) ("However, the EPA recognizes that condensable emissions are also PM10, and that emissions that contribute to ambient PM10 * * * concentrations are the sum of in-stack PM10, and condensable emissions.")

3. The Draft Permit Requirements to Control Unconfined Particulate Emissions Are Inadequate and Unenforceable.

The Draft Permit establishes two requirements for unconfined particulate emissions: (a) All conveyors and convey transfer points will be enclosed to the extent practical, so as to preclude PM emissions and (b) Water sprays or chemical wetting agents and stabilizers will be applied to storage piles, handling equipment, roadways, etc as necessary to minimize opacity. Draft Permit at. 9, Condition 20. This condition is not adequate to address PSD requirements.

Statement in TEPD rega use of cover handling/storing facilities

First, the Draft Permit does not contain any BACT determination, emission limits, compliance provisions, or recordkeeping provisions for these unconfined (i.e., fugitive) particulate emissions. BACT is required for fugitive emission sources, and the permit must include BACT emission limits for those sources that "demonstrate protection of short term ambient standards (limits written in pounds/hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification and recordkeeping requirements)." NSR Manual, p. B.56. The PM10 emissions from these sources were calculated assuming certain control efficiencies based on implementation of specific control measures, and the controlled emissions were included in Class II modeling. See Application, Appendix A.

Second, the Draft Permit contains vague and unenforceable language that gives the operator virtually complete discretion with regard to fugitive dust control measures. Draft Permit at 9. Moreover, the regulation cited, 62 F.A.C. § 62-296.320(4)(c), is simply the general SIP provision, which does not include specific measures related to the Seminole facilities.

The purpose of a permit is to individualize a regulation to site-specific conditions. The condition, proposing to implement Rule 62-296.320(4)(c), F.A.C, is not responsive as no site-specific conditions are included in the Permit to add detail or to assure PM/PM10 control efficiencies assumed in the emission calculations are achieved in practice.

Third. the permit language is inconsistent with the assertion of control measures contained in the Technical Evaluation because it fails to adopt any of the specific dust control measures discussed. For its part, the Technical Evaluation merely provides a description of control measures without any analysis of their effectiveness and without selecting BACT, as required for a PSD pollutant. Technical Evaluation and Preliminary BACT Determination, Aug. 21, 2006, 16-17. The permit must contain specific, effective, and enforceable measures to control unconfined particulate emissions.

Frequency of watering is determined by current operator and weather/material conditions

Fourth, the term "as necessary" is ambiguous and thus unenforceable. The frequency of watering determines the amount of control that is achieved. In order for a permit to be enforceable as a practical matter, a permitting agency must include specific legal obligations in the permit so that sources will observe the permit constraints.

National Mining Assoc., 59 F.3d at 1363. It is a canon of interpretation that any conditions that are vague, contradictory, or confusing are unenforceable. Terms such as "as necessary" are subjective and therefore unenforceable.

Fifth, the ambiguous language in this condition allows enforcement discretion, especially discretion in the determination of whether a violation has occurred, and thus is unenforceable. In re: Indeck-Elwood, LLC, EAB Slip Opinion, PSD Appeal No. 03-04 (Sept. 27,2006), p. 72, footnote 101. A permit may not reserve agency discretion to determine whether a violation has actually occurred. A condition that only requires watering "as necessary," when the underlying emission calculations assumes a specific level of control, reserves enforcement discretion to FDEP and prevents citizens from being able to enforce the permit without a decision by FDEP, thus allowing the source to negotiate the condition "off-permit." As a result, reserving enforcement and violation decisions as fugitive sources for the agency renders the Permit unenforceable by citizens. Interestly

The Permit should be modified to include specific emission limits and methods of control for all fugitive sources to assure that the claimed emissions used in the Class II modeling are achieved. These should include limits on and monitoring reporting of all factors assumed without support in the emission calculations.

4. The Draft Permit Does Not Contain Any BACT Conditions For Material Handling

The project emits PM and PM10 from equipment used to handle, convey, and store materials including coal, limestone, gypsum, fly ash, and bottom ash. This equipment is vented through fabric filter baghouses at transfer points. Ap., Sec. 4.3.6. Some of this equipment is new and some is existing sources that will be either modified, or used at a higher rate. For these sources, the Application and Technical Evaluation claim a BACT PM limit of 0.01 grains per dry standard cubic foot ("gr/dscf").

The application does not include a top-down BACT analysis for the material handling equipment. Instead, the application asserts with no support that certain levels of control or control options constitute BACT. Ap., p. 53. The Technical Evaluation copies the Application, simply stating that the baghouses at transfer points will meet a design emission rate of 0.01 gran/cubic feet. Technical Evaluation, p. 17. This unsupported assertion is not carried forward and required as a permit condition. Thus, there is no BACT analysis nor BACT limits for material handling point sources. Lower levels have been recently permitted for material handling baghouses at other similar sources including:

- 0.004 g/dscf for coal and limestone collectors at the Elm Road, WI
- 0.005 g/dscf for coal and limestone collectors at the MidAmerican, IA
- 0.009 g/dscf for coal collectors at the Wygen 2, WY
- 0.005 g/dscf for baghouses at Indeck-Illwood, IL

Thus, BACT for PM/PM10 for material handling operations vented to a baghouse should be a grain loading of no more than 0.004 gr/dscf.

The grain loading that was selected as the design basis is not included in the Draft Permit and thus is not enforceable. BACT limits must be enforceable, which means a condition limiting emissions must be included in a federally enforceable permit together with monitoring, recordkeeping and reporting to assure that they are met. The applicant should be required to prepare a BACT analysis for material handling equipment, the Draft Permit revised to include the limit, and recirculated for public review.

5. FDEP Must Consider Dry Cooling in its PM BACT Analysis.

Seminole proposes to use cooling towers at its power plant. Cooling towers result in a significant emission of PM10. Dry cooling is clearly an available technology to eliminate most of the PM10 emissions associated with cooling. See e.g., Pogliani v. U.S. Army Corps of Engineers, 166 F. Supp. 2d 673 (N.D. N.Y. 2001).

The Seminole BACT analysis must be redone to consider dry cooling as a proven technology to reduce PM10 emissions. It is especially critical that the BACT analysis seriously consider dry cooling because it would reduce impacts to the water resource used for cooling water. Protection of water resources is extremely important in Florida. The state's economy and ecosystems depend on clean and abundant fresh water. Dry cooling, or some hybrid thereof, would greater reduce the PM10 emissions and the impacts on the proposed water source.

Is the PM from cool. towers sal!

In the recent Weston 4 proceeding in Wisconsin, Mr. Bill Powers explained the benefits of dry cooling technology. Use of an air-cooled condenser ("ACC") would reduce overall plant water consumption by at least 95 to 98%. ACCs have been used on large coal-fired power plants for over 25 years. The 330 megawatt Wyodak coal-fired power plant in Wyoming has successfully operated with an ACC for over 25 years. The largest ACC-equipped coal fired power plant in the world, the 4,000 megawatt Matimba facility in South Africa, has been operating successfully for over 10 years. Two coal-fired units in Australia have been operational since 2001. A number of new coal-fired power plants have been proposed in New Mexico over the last three years. In all cases the project proponents have voluntarily incorporated ACC into the plant design to minimize plant water use. A 36 Megawatt pulverized coal unit in Iowa, Cedar Falls Utilities Streeter Station Unit 7, was retrofitted with dry cooling in 1995 due to highway safety concerns caused by the winter wet tower plume. The use of dry cooling on pulverized coal fired power plants is well established.

The benefits of using dry cooling include:

- No water withdrawals
- No brine discharge to river
- No need for investment in raw water clarification system or intake structure upgrades

- No aesthetic issues related to visible vapor plumes
- No highway safety or equipment operation issues with vapor plumes in the winter
- No cooling tower drift emissions or particulate deposition

Finally, wet cooling can result in significant public health impacts in the surrounding community. For example, the Cooling Technology Institute ("CTI") advises that permitting agencies should assume that any cooling tower system harbors the Legionella bacteria. In this case, the Legionella bacteria will be emitted as a component of the PM10 emitted by the wet cooling towers. Legionella bacteria emitted in cooling tower drift are hazardous substances and need to be addressed in the permit application. The most straightforward solution to the difficult problem of Legionella bacteria in cooling tower drift is to utilize dry cooling technology.

E. BACT Is Required For Sulfuric Acid Mist

The Application concluded that BACT is not required for sulfuric acid mist (SAM) because the facility nets out of PSD. However, the netting analysis failed to include the increase in SAM emissions from the emergency diesel generator and the ZLD spray dryer, both of which burn fuel oil. Ap., Table 2-11. The amount of SAM from these two combustion sources alone exceed the PSD significance threshold of 7 ton/yr.

No way

Further, SAM emissions from Units 1 and 2 will significantly increase when the new SCRs are installed. The SCR catalyst converts SO_2 created in the boiler to SO_3, which subsequently combines with water to form SAM.[5] The Permit for Units 1 and 2 require the installation of an alkali injection system to reduce SAM emissions to the pre-SCR baseline. Seminole Units 1 & 2 Permit at 5, Condition 5. However, this reduction is not adequate to assure that the increase in emissions from Unit 3 plus the oil-fired equipment do not increase by 7 ton/yr or more. The Draft Permit does not explain how the Units 1-3 cap of 2,129 ton/yr would be met or contain the monitoring and recordkeeping required to assure that it win fact ould be met. Thus, we conclude that BACT is required for SAM.

The SAM limit included in the Permit, 0.005 lb/MMBtu, is not BACT for SAM. Lower limits have been permitted including:

- 0.002 lb/MMBtu for SEI Birchwood
- 0.0042 lb/MMBtu for MidAmerican Energy
- 0.0046 lb/MMBtu for Prairie Energy Corn Belt Energy.
- 0.001 lb/MMBtu for TS Power
- 0.0015 lb/MMBtu for Parish Unit 8
- 0.0014 lb/MMBtu for Santee Cooper Cross

[5] R.K. Srivastava and others, Emissions of Sulfur Trioxide from Coal-Fired Power Plants, J. Air & Waste Manage. Assoc., v. 54, 2004, pp. 750-762.

- 0.004 lb/MMBtu for Parish Units 5-7
- 0.0045 lb/MMBtu for Manitowoc
- 0.0010 lb/MMBtu for Newmont
- 0.0024 lb/MMBtu for AES Puerto Rico
- 0.004 lb/MMBtu for Trimble

It is within the "range"

Thus, we urge FDEP to revisit the SAM BACT issue. It is very unusual for a modified coal fired power plant source to net out of SAM when its other units are retrofitted with SCR due to the very large increase in SAM from SCR retrofit. We believe if the netting analysis is done correctly, BACT will be required for SAM and that a proper BACT analysis will result in a lower SAM emission limit.

F. Permit Limits for Visible Emissions (Opacity) Do Not Constitute BACT

The permit contains an opacity limit of 20%, except that it allows a maximum of 27% for not more than six minutes per hour. See Seminole Draft Permit at 8. This purports to be a BACT limit. However, the Applications and Technical Evaluation do not contain a BACT analysis. Further, BACT for opacity from a coal-fired fired power plant is much lower. Moreover, the permit must contain a visible emission limit for regulated pollutants (i.e., PM and SAM)[6] that is based on the maximum degree of reduction achievable with the best pollution control option for Seminole. 62 F.A.C. § 62-212.400.

As a PSD permit, the preconstruction permit for Seminole must require BACT for all regulated pollutants. 62 F.A.C. § 62-212.400(10)(b). BACT is defined as an "emission limitation, including a visible emission standard . . .." 62 F.A.C. § 62-210.200; *see also* 42 U.S.C. § 7479(3); 40 C.F.R. § 52.21(b)(12). Although a BACT limit for PM or SAM typically includes an emission rate limit (i.e., pounds per hour or pounds per million Btu heat input), a BACT limit must nevertheless also "includ[e] a visible emission standard." *Id.*

Other recent coal plant permits include visible emission as part of the BACT limits for those facilities. For example, the Springerville facility in Arizona has a BACT limit of 15% opacity, and the Mid-America facility in Council Bluffs has an opacity limit of 5%.[7] The Wisconsin Department of Natural Resources set a 10% opacity limit as BACT for the Fort Howard (Fort James) Paper Company's 500 MW CFB boiler. The Minnesota Pollution Control Board also considered the issue and determined that a 5% opacity limit should be established based on BACT. The maximum achievable visible

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[6] A visible emission standard is a limit on "light scattering particles," which include both fine particulate matter ("PM") and sulfuric acid mist ("SAM") aerosols. Both PM and SAM are regulated under PSD and, therefore, a complete PSD permit must contain a BACT limit which includes a visible emission limit based on BACT for PM and SAM.

[7] *See* Iowa DNR Permit No. 03-A-425-P, §10a (Permit available online at http://aq48.dnraq.state.ia.us:8080/psd/7801026/PSD_PN_02-258/03-A-425-P-Final.pdf.)

emission reduction for a "circulating fluidized bed" ("CFB") boiler, however, is much lower than 5% opacity. For example, the JEA Northside CFB in Jacksonville, Florida, conducted a compliance test during the summer of 2002, while burning high-sulfur coal, and measured opacity of less than 2%.[8] Testing done by Black & Veatch for the Department of Energy showed visible emissions at the JEA facility of 1.1 and 1.0% opacity.[9]

The visible emission limit in the permit does not comply with applicable regulations. 62 F.A.C. §§ 62-212.400(10)(b), 62-210.200. A complete BACT limit for PM and SAM requires a visible emission limit of no more than 2% opacity based on the results of testing at the JEA Northside facility. See Goodrich, *supra*, p. 16. Indeed, with a fabric filter baghouse for PM_{10} control, an opacity BACT limit should be no higher than 10%, if not lower, with the Teflon-coated bags currently used for BACT technology. For example, the state of Utah recently issued two permits for coal-fired power plants to be equipped with fabric filter baghouses—Intermountain Power Unit 3 and the Sevier power plant—which both have 10% opacity limits required as BACT.

Thus, FDEP must evaluate PM and opacity BACT more thoroughly, considering the lower PM and opacity BACT limits that have been required at other coal-fired power plants as BACT.

III. THE BACT PERMIT LIMITS ARE UNLAWFUL BECAUSE SEMINOLE FAILED TO ASSESS HOW EMISSIONS FROM UNIT 3 MAY IMPAIR THE OKEFENOKEE, WOLF ISLAND, AND CHASSAHOWITZKA NATIONAL WILDERNESS AREAS' SOILS AND VEGETATION.

A PSD permit may not be issued until an analysis has been completed assessing the "impairment to * * * soils and vegetation that would occur as a result of the source." 40 C.F.R. § 52.21(o); 62 F.A.C. § 62-212.720(8)(a). This analysis must begin with "an inventory of soils and vegetation types found in the impact area." NSR Manual at D.4. Seminole has conducted no inventory and its limited analysis did not consider sensitive soils and vegetation within the impact area. Air Permit Application, pp. 79-83.

The Clean Air Act requires FDEP to consider and protect natural resources. Among the purposes of the PSD program are to "preserve, protect and enhance the air quality in * * * areas of natural, recreational, scenic or historic value." 42 U.S.C. § 7470 (emphasis added). To preserve and protect such areas the Act mandates that "[n]o major emitting facility * * * may be constructed * * * unless -- * * * (2) * * * the required analysis has been conducted in accordance with regulations promulgated by the Administrator." 42 U.S.C. § 7475(a). One such PSD regulation requires that the applicant "shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source." 40 C.F.R. § 52.21(o); 62 F.A.C. § 62-212.720(8)(a). U.S.

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[8] William Goodrich, et al., Summary of Air Emissions from the First Year Operation of JEA's Northside Generating Station, Presented at ICAC Forum '03, p. 16.
[9] *See* Black & Veatch, Fuel Capability Demonstration Test Report 1 for the JEA Large-Scale CFB Combustion Demonstration Project, DOE Issue Rev. 1 p. 12 (Sept. 3, 2004).

EPA has further explained that such an analysis "should be based on an inventory of soils and vegetation types found in the impact area [and] [t]his inventory should include all vegetation with any commercial or recreational value, and may be available from conservation groups, State agencies, and universities." NSR Manual at D.4 (emphasis added).

An air quality impact analysis is critical because "[i]njury to vegetation is one of the earliest manifestations of photochemical air pollution, and sensitive plants are useful biological indicators of this type of pollution." *2002 IEPA Air Quality Report* at 1. In 1997, US EPA revised the secondary NAAQS for ozone precisely because the 1-hour standard "does not provide adequate protection to vegetation from the adverse effects of O3." 62 Fed. Reg. 28855, 38875 (July 18, 1997). Moreover, ozone "concentrations within the range of 0.05 to 0.10 ppm have the potential over a longer duration of creating chronic stress on vegetation that can result in reduced plant growth and yield * * * and injury from other environmental stresses." *Id.* Even more alarming, "[a]dverse effects on sensitive vegetation have been observed from exposure to photochemical oxidant concentrations of about 100 ug/m3 (0.05 ppm) for 4 hours." Illinois EPA, 2002 Illinois EPA Annual Air Quality Report at 1 (2002).

Ozone is not the only pollutant that harms vegetation. There "are sensitive vegetation species . . . which may be harmed by long-term exposure to low ambient air concentrations of regulated pollutants for which there are no NAAQS." NSR Manual at D-4. As an example, U.S. EPA notes that "exposure of sensitive plant species to 0.5 micrograms per cubic meter of fluorides (a regulated, non-criteria pollutant) for 30 days has resulted in significant foliar necrosis." *Id.* This example is relevant because Seminole 3 seeks to emit 7.5 tons per year of fluorides. FDEP, Technical Evaluation and Preliminary BACT Determination, Seminole 3 at 6 (Aug. 21 2006).

There are three Class I areas within 200 km of PSD Class I area. Seminole Application at 59. The nearest Class I area is the Okefenokee National Wildlife Area, which includes the Okefenokee Wildlife Refuge within its borders. It is located approximately 108 km north of the proposed Seminole 3. Id. The Okefenokee NWA contains the Okefenokee Swamp, which is covered with cypress, blackgum, and bay forests scattered throughout a flooded prairie made of grasses, sedges, and various aquatic plants.[10] The peripheral upland and almost 70 islands within the swamp are forested with pine interspersed with hardwood hammocks. With its varied habitats, the Okefenokee has become an area known for its abundance of plants, wildlife and birds. The Okefenokee is inhabited by 621 plants, 39 fish, 37 amphibians, 64 reptiles, 234 birds, and 50 mammal species. The Okefenokee Wildlife Refuge is home to endangered

[10]U.S. Fish and Wildlife Serv., Okefenokee Wildlife Refuge available at http://www.fws.gov/okefenokee/.

wildlife and plants, including the Florida panther, American Alligator, and Indigo Snake.

The second closest National Wilderness Area is the Chassahowitzka National Wildlife Refuge, which is located 137 km to the southeast of the proposed Seminole 3. Air Permit Application, p. 59. The Chassahowitzka consists of coastal saltmarsh, shallow bays, tidal streams, and rivers, mangrove islands, and coastal maritime hammock.[12] The refuge provides habitat for approximately 250 species of birds, over 50 species of reptiles and amphibians, and at least 25 different species of mammals. Endangered and threatened species on the refuge include manatees, sea turtles, and bald eagles.[13]

The Wolf Island National Wildlife Refuge is located 186 km to the north. Air Permit Application, p. 59. Wolf Island NWR, which includes Egg Island and Little Egg Island, was established on April 3, 1930 as a migratory bird sanctuary. The refuge consists of a long narrow strip of oceanfront beach backed by a broad band of salt marsh.[14] Several species of threatened and endangered species can be found within the Wolf Island NWR, including the bald eagle, American alligator, loggerhead sea turtle, piping plover, and wood stork.[15]

Seminole did not conduct an inventory of the soils and vegetation within the Okefenokee, Wolf Island, and Chassahowitzka National Wilderness Areas ("NWA"). Moreover, Seminole's "analysis" did not consider any site specific information about the land uses around its proposed facility. Air Permit Application, p. 79-83.

1. Seminole did not conduct an inventory of the soils and vegetation within the impact area, so FDEP should not issue a PSD permit.

Seminole did not conduct an inventory of the Okefenokee, Chassahowitzka, and Wolf Island National Wilderness Areas' soils and vegetation. Air Permit Application, pp. 79-83. Specifically, Seminole did not compile information on soil condition at any of these NWAs, including compiling information on pH, nutrient levels, trace element content, buffering capacity, base saturation. Instead Seminole simply states that "soils of Class I areas are <u>generally</u> classified as histols or entisols." <u>Id</u>. at 80 (emphasis added). Under the Clean Air Act and Florida's SIP, Seminole is required to specifically inventory

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[11] U.S. Fish and Wildlife Serv., Okefenokee National Wildlife Refuge Amphibians, Fish, Mammals and Reptiles List available at http://www.fws.gov/okefenokee/okefenokee_amphib_fish_mam_rep98.pdf.
[12] U.S. Fish and Wildlife Serv., Chasshowitzka National Wildlife Refuge, available at http://www.fws.gov/chassahowitzka/.
[13] <u>Id</u>.
[14] U.S. Fish and Wildlife Serv., Wolf Island National Wildlife Refuge, available at <u>http://www.fws.gov/wolfisland/index.htm</u>.
[15] U.S. Fish and Wildlife Serv., Threatened and Endangered Species of Savannah Coastal Refuges, available at <u>http://www.fws.gov/savannah/endangered.htm</u>.

the soils of these three National Wilderness Areas and not make assumptions based on generalizations of Class I areas. Seminole also did not inventory the vegetation, including compiling information on the presence of rare and endangered plants and information of the condition of the vegetation in these three National Wilderness Areas. Moreover, Seminole did not gather any site specific information about the land uses around Seminole 3. In short, Seminole did not adequately consider these three national resources or the area surrounding the proposed plant.

Seminole must conduct inventory of the soils and vegetation within the impact area, particularly focusing on the Okefenokee, Chassahowitzka, and Wolf Island National Wilderness Areas. FDEP should not issue a permit for Seminole 3 until this is done because it is patently unlawful to do so. 42 U.S.C. § 7475(a) ("no major emitting facility * * * may be constructed * * * unless * * * the required analysis has been conducted.")

2. FDEP must require a soils and vegetation analysis because there is evidence that Seminole's emissions threaten the surrounding soil and vegetation.

As discussed in detail below, Seminole's evaluation of impacts to Class I areas is unlawfully deficient because Seminole analyzed emission impacts as if they existed in a bubble. Seminole must actually determine the impacts of Seminole 3 on these areas, in conjunction with pollution from other sources and regional background. Seminole originally accounted for impacts from other sources and regional haze in its Class I air quality analysis. However, when that analysis demonstrated significant impacts to the Okefenokee and Chassahowitzka National Wilderness Areas, Seminole isolated its analysis to the pollution from the Seminole plant alone. Under the proper analysis it is undeniable that Seminole 3 will impact the surrounding National Wilderness Areas. As a part of Seminole's soil and vegetation analysis, it must consider the impacts of each of the pollutants on soil and vegetation, including any identified rare species and other species with particular ecological or economical value.

IV. THE ANALYSIS MERCURY EMISSIONS FROM SEMINOLE 3 VIOLATES THE PREVENTION OF SIGNIFICANT DETERIORATION PROVISIONS OF 62 F.A.C. § 62-212.400.

Mercury is an extremely hazardous neurotoxin that is dangerous at very low levels. Florida residents are already subject to unacceptable mercury levels. <u>See section</u> VII.A.2 *supra*. It is incumbent upon FDEP to protect public health by requiring appropriate mercury limits that are both attainable and enforceable, and Florida law continues to require analysis for mercury under the Prevention of Significant Deterioration (PSD) provisions notwithstanding changes in federal law.

The analysis supporting the Draft Permit limits is fundamentally flawed. The Draft Permit exempts Seminole Unit 3 from PSD analysis for mercury based on the conclusions that the new unit will emit 46.3 pounds per year of mercury and that Seminole 1 and 2 will reduce their emissions by 46.3 pounds per year. Air Permit

Application and Prevention of Significant Deterioration Analysis, p. 30. These unsupported conclusions are based on a cursory, hypothetical, and unproven analysis. The permit limits for all three Seminole units and emissions credits calculated for Seminole Units 1 and 2 are potentially unachievable and unenforceable. A more realistic analysis shows that the projected mercury emissions will likely be much greater, exceeding the threshold for PSD review.

Once the new unit is built, retrofitting it to reduce mercury emissions to permit levels would be impractical and uneconomical. FDEP must insist on both adequate analysis and adequate control measures before issuing the permit.

A. Mercury Emissions Are Subject to PSD Review Notwithstanding Changes to Federal Law.

The Draft Permit refers to the federal mercury emissions standard (40 C.F.R. 60.45Da), yet fails to acknowledge that state regulations related to mercury impose additional requirements. Florida regulations continue to set a PSD significance threshold for mercury of 0.1 tons per year (200 lbs/yr.). 62 F.A.C. § 62-210.200(264)(a)(2).[16] As discussed below, proper calculations demonstrate that mercury emissions from Seminole 3 reach the PSD significance threshold, so PSD analysis is therefore required. This analysis includes the application of the "best available control technology for each PSD pollutant that the source would have the potential to emit in significant amounts." 62 F.A.C. § 62-212.400(10)(b). Thus, FDEP must require a BACT analysis for mercury emissions from Seminole Unit 3.

B. The Analysis of Mercury Emissions Levels Is Flawed.

1. The permit uses an inconsistent and artificially high baseline.

Seminole has claimed that the existing emissions level from Units 1 and 2 is 0.065 tons per year (130 lbs/yr) for mercury. The Draft Permit is based on a proposed 0.023 tons per year (46 lbs/yr) reduction in mercury emissions from Units 1 and 2. *See* Table 1. These reductions are illusory, because the baseline is artificially high, and because, as discussed below, the supposed emissions reductions are unproven.

[16] Unless and until the EPA approves revisions to Florida's PSD program into Florida's SIP, FDEP cannot issue PSD permits that conflict with the existing SIP. General Motors Corp. v. United States, 496 U.S. 530, 540 (1990) ("There can be little or no doubt that the existing SIP remains the "applicable implementation plan" even after the State has submitted a proposed revision."); United States v. Murphy Oil USA, Inc., 143 F.Supp.2d 1054, 1101 (W.D. Wis. 2001) (SIP cannot be changed without EPA approval.).

This is a commitment by the facility to not exceed past actual Hg emissions. Hg emissions from the new unit are clear < 200 lb/yr regardless of this commitment

Table 1 – Pollutant Emissions Net Increases for the Seminole 3 Project,
FDEP Preliminary Evaluation and BACT Determination, August 21, 2006, Page 6.

The table below illustrates the applicant's estimate of the "post-change" emissions (identified as "Net Emissions Change", inclusive of the complete SGS Unit 3 project as compared to the Baseline Actual Emissions. Based upon the applicant's submittals, only some PSD pollutants are expected to exceed the significant emission rate, and thus trigger a BACT review.

Pollutant	Baseline Actual Emissions (TPY)	SGS 3 Projected Emissions (TPY)	SGS 1/2[A] Emission Reductions (TPY)	Projected Actual Emissions (TPY)	Net Emissions Change (TPY)	Significant Emission Rate (TPY)	PSD Review Required ?
SO_2	29074	5437	5437	29074	0	40	NO
NO_X	23289	2336	2336	23289	0	40	NO
CO	13451	4936	0	18387	4936	100	YES
VOC	108	132	0	240	132	40	YES
PM	822	519	0	1341	519	25	YES
PM_{10}	822	511	0	1333	511	15	YES
SAM	2129	164	164	2129	0	7	NO
Mercury	0.065	0.023	0.023	0.065	0	0.1	NO
Pb	No data	0.247	0	NA	0.247	1	NO
HF	No data	7.5	0	NA	7.5	3	YES

Note A: 1070025-004-AC establishes enforceable emission limits for SGS 1 and 2, which in combination with the requested limits in this project, keep SGS-3 from triggering a PSD/BACT Review for SO_2, NO_X, SAM and Hg. These emission limitations will also be identified in the SGS-3 permit since PSD avoidance is applied.

A simple comparison to the emissions levels that Seminole has reported in TRI (see Table 2) shows that the baseline should be, at most, 99 lbs/year rather than 130 lbs/year. Using 2004–2005 as the baseline years, the average mercury emissions are 99 lbs/year (140 lbs + 58 lbs = 198 lbs/2 years = 99 lbs/year)

Table 2 – TRI Reported Mercury Emissions from Seminole Generating Station

Chemical Name	Chemical Name	Media	Unit Of Measure	2005	2004	2003	2002	2001	2000
MERCURY COMPOUNDS	(TRI Chemical ID: N458)	AIR STACK	Pounds	140	58	77	82	94	95

http://oaspub.epa.gov/enviro/tris_control.tris_print?tris_id=32177SMNLGUSHWY

2. The anticipated emissions reductions are based on vague and variable co-control measures.

The emissions reductions at Seminole 1 and 2, as well as the emissions reductions at Seminole 3, are based on a vague anticipated benefit of co-control resulting from pollution control equipment installed to control other pollutants. This benefit is not quantified and no performance guarantee is provided by equipment vendors. The vague and unsubstantiated claim is used to avoid PSD review for mercury, which is required under 62 F.A.C. § 62-210.200(264)(a)(2), and to avoid installing BACT for mercury, which is required under 62 F.A.C. § 62-212.400(10)(b).

The analysis states:

> "SGS Unit 3 will feature supercritical pulverized coal technology with modern emission controls. The Unit 3 air pollution control equipment will include wet Flue Gas Desulfurization (FGD) for SO_2 removal, selective catalytic reduction (SCR) for control of nitrogen oxides (NOx), electrostatic precipitator (ESP) for collection and removal of fine particles, a Wet ESP (WESP) for control of sulfuric acid mist (SAM), with fluoride (HF) and mercury (Hg) removal to be accomplished through co-benefits of the above technologies. Fuel (coal and petroleum coke) for SGS Unit 3 will be delivered by an existing rail system."

(FDEP Preliminary Evaluation and BACT Determination, August 21, 2006, p. 4)(emphasis added).

The Draft Permit and supporting documents contain no demonstrated basis for this assertion of control performance, actual mercury reduction achieved by co-control has varied widely in actual application from plant to plant, and the underlying science is still not well understood,[17] making predictions for any given facility difficult. There is no control efficiency calculated or required under the permit. There is no vendor guarantee of control efficiency. FDEP takes this claimed control, which is incorrectly calculated (as shown below), and allows Seminole to avoid PSD review.

3. The mercury emission rates are not based on appropriate or replicable calculation methods.

The emissions increases calculated for Seminole 3 are not consistent with federal guidance, as is shown by reference to Table 2-3 of the Air Permit Application (reproduced herein as Table 3). AP-42 is federal guidance and contains a reliable value for uncontrolled mercury emissions. The record of decision established by FDEP omits consideration of uncontrolled levels and of control efficiency even though AP-42 and the COALQUAL database references cited by Seminole provide sources for these numbers. Another source of information on uncontrolled mercury emissions is a Florida DEP Study titled "Trends of Mercury Flow over the US with Emphasis on Florida" (FDEP Study).[18]

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[17] J. Staudt and W. Jozewicz, Mercury Control from Coal-Fired Electric Utility Plants – A Review of Technology Status and Cost, ICAC, 2005, pdf 5 shows wide variation in achievable Hg control for the controls proposed for Seminole; A.A. Presto and E.J. Granite, Survey of Catalysts for Oxidation of Mercury in Flue Gas, Critical Review, Environmental Science & Technology, v. 40, 2006, pp. 5601-5609; S.B. Ghorishi and others, Effects of SCR Catalyst and Wet FGD Additive on the Speciation and Removal of Mercury within a Forced-Oxidized Limestone Scrubber, ICAC 2005.

[18] "Trends of Mercury Flow over the US with Emphasis on Florida," Janja D. Husar and Rudolf B. Husar, Florida Department of Environmental Protection Mercury Program, June 30, 2001.

TABLE 2-3
TRACE METAL HAP EMISSIONS ESTIMATES FOR SECI SGS UNIT 3

	Trace Metal in Coal											
	Antimony	Arsenic	Beryllium	Cadmium	Chromium	Cobalt	Lead	Manganese	Mercury	Nickel	Selenium	Vanadium
Emissions-EPA Factors (EF = a x (C/A x PM)[b]												
Multiplier - a	0.92	3.1	1.2	3.3	3.7	1.7	3.4	3.8		4.4		3.8
Exponent - b	0.63	0.85	1.1	0.5	0.58	0.69	0.8	0.6		0.48		0.6
Concentration (C) (ppm)	1.64	29.72	3.330	0.72	19.21	8.39	22.890	44.97		172.057	4.08	520.736
Actual PM Concentration (PM) (lb/mmBtu)	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150		0.0150		0.0150
Ash Concentration (A) (fraction)	0.1273	0.1273	0.1273	0.1273	0.1273	0.1273	0.1273	0.1273		0.1273		0.1273
Emission Factor (lb/10^12 Btu)	0.327	8.996	0.429	0.961	5.943	1.687	7.520	10.335	0.707	18.654	17.317	44.927
Heat Input (mmBtu/hr)	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500
Maximum Fuel Input (lb/hr)	636,672	636,672	636,672	636,672	636,672	636,672	636,672	636,672	636,672	636,672	636,672	636,672
Emissions (lb/hr)	0.002	0.067	0.003	0.007	0.045	0.013	0.056	0.078	0.005	0.140	0.130	0.337
Uncontrolled (lb/hr)	1.044	18.922	2.120	0.458	12.230	5.342	14.573	28.631		109.544	2.598	331.538
Removal	99.77%	99.64%	99.85%	98.43%	99.64%	99.76%	99.61%	99.73%		99.87%	95.00%	99.90%
Emissions (tons/yr)	0.011	0.296	0.014	0.032	0.195	0.055	0.247	0.339	0.023	0.613	0.569	1.476

Sources: EPA,1998, AP-42, Table 1.1-16 (all metals except mercury, selenium and vanadium). Trace Metal Concentration based on upper 95% Confidence Interval from USGS COALQUAL Database Trace Elements for the Central Appalachian Region
http://energy.er.usgs.gov/coalqual.htm
Controlled Mercury emissions based on 7.05E-06 lb/MW-hr
Controlled Selenium emissions based on 95% control from FGD system
EPA Emission Factor Rating: A-Excellent
Souce: EIR NAPP EIR EIR NAPP EIR EIR EIR
Legend for source: EIR = Eastern Interior Region (Illinois, Indiana, Western Kentucky), CAPP = Central Appalachian, NAPP = Northern Appalachian

A USGS report titled "Mercury in U.S. Coal: Abundance, Distribution, and Modes of Occurrence, September, 2001," provides a mean value of 0.15 ppm for Central Appalachian coal based on 1,747 samples. This equates to 837 lbs per year of mercury emissions using the 636,672 lbs/hr of coal also listed in Table 3:

> **636,672 lbs/hr coal x 8,760 hrs/yr = 5.58×10^9 lbs/yr coal burned, 5.58×10^9 x 0.15 ppmw = 837 lbs/yr mercury.**

(Hg CEMS?)

EPA's "Control of Mecury Emissions from Coal-Fired Electric Utility Boilers"[19] provides a value of 0.20 ppm for Appalachian bituminous coal. Using EPA's value would increase emissions by 33% to 1,116 lbs/yr of mercury. The Florida DEP Study gives a value of 0.24 ppm for Appalachian coal, which this is 60% higher the USGS value of 0.15 and results in an estimated 1,339 lbs/yr of uncontrolled mercury emissions.

There are many available resources, including documents Seminole used for calculating emissions of other metals, that provide values that Seminole and FDEP failed to include and evaluate for uncontrolled emissions. These values for uncontrolled emissions also provide a method for evaluating the promised level of control, promised emissions reductions and the claimed existing emissions rates. FDEP should not have issued this proposed permit without a thorough examination of these factors and a determination if the required levels of control were guaranteed to occur with the proposed control equipment.

FDEP fails to report an uncontrolled emissions rate in the appropriate column of Table 2-3. An additional footnote in Table 3 gives a value of 7.05×10^{-6} lb/MW hr, which is inconsistent with the reference to the COALQUAL database and equates to the 0.023 tpy or 46 lbs/yr value discussed above. FDEP has apparently relied on this unsubstantiated value in issuance of this permit. As this value is inconsistent with the reference to the USGS COALQUAL database, it is apparently provided without any reference. FDEP may not rely on this unsubstantiated value for issuance of this permit.

It is possible that the reference in Table 3 to 7.05×10^{-6} lb/MW hr (7.500 lb/1×10^{12} Btu) was derived from a November 2005 stack test conducted on Units 1 and 2. However, this value is also inconsistent with the results of those tests. The stack test values in Appendix A average about 1.41 lb/1×10^{12} Btu, or twice this reported value. This analysis is problematic both because the value is inconsistent with the test and because there are several problems with this method of testing for mercury emissions. First, the test used the two-trap (rather more accurate three-trap) method. Second, Method 324 only measures vapor phase mercury. It does not measure particulate mercury, which could comprise a significant fraction of the mercury in facilities with older ESPs, such as Seminole Units 1 and 2. Third, the test report included in Appendix A to the Application did not identify the fuel that was burned during the test (100% coal, coal/pet-coke blend) nor the mercury content of the fuel that was fired

[19] United States Environmental Protection Agency EPA-600/R-01-109 April 2002.

during the test. Thus, it is not possible to determine whether the test is representative of the fuels that would have been burned during the 2004-2005 baseline and in the future. Fourth, the detailed sampling data shows that breakthrough occurred in every single run (Application, Appx. A, Attach. 1), indicating that some of the mercury likely escaped detection. Fifth, the results of this test indicate that the level of mercury control at Seminole 1 and 2 was either remarkably high, or that the mercury in the coal fed during the tests was abnormally low. Finally, the test report notes that "results are consistent previous Ontario Hydro measurement," which, in contrast to the results provided in Appendix A, separately reported particulate, oxidized, and gaseous elemental mercury. These other relevant test results should be produced to FDEP to assist in evaluating the relevance of the data provided in Appendix A.

The appropriate federal reference is the AP-42 values that Seminole used for everything in Table 3 except mercury, selenium and vanadium. This EPA reference gives 16 lb/10^{12} Btu for uncontrolled mercury emissions (AP-42 Chapter 1.1, Table 1.1-17), which results in 1,026 lbs/year of uncontrolled mercury emissions:

> **636,672 lbs/hr coal x 8,760 hrs/yr = 5.58 x 10^9 lbs/yr coal burned * 11,500 Btu/lb coal (as representative of the two design blends specified in Table 2-1 of the PSD Permit Application) = 6.41 x 10^{13} Btu/yr x 16 lb/10^{12} Btu = 1,026 lbs/year of uncontrolled mercury emissions per year**

For controlled emissions, AP-42 gives 8.3x10^{-5} lb/ton of coal combusted (or approximately 231 lbs/yr):

> **636,672 lbs/hr coal x 8,760 hrs/yr = 5.58 x 10^9 lbs/yr coal burned, 5.58 x 10^9 x 8.3 x 10^{-5} lb/ton of coal combusted = 231 lbs/yr mercury**

Comparing the 0.707 lb/10^{12} Btu that Seminole has provided with EPA's referenced uncontrolled factor of 16 lb/10^{12} Btu, it can be seen that Seminole is projecting an emissions level that is reduced by approximately 96% over uncontrolled levels ((16-0.707)/16 = 95.6%). This level of control represents an extremely high level of performance for the unsubstantiated and unquantified benefits that have been attributed to co-control.

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Comparing the 0.707 lb/10^{12} Btu that Seminole has provided with EPA's referenced uncontrolled factor of 16 lb/10^{12} Btu, it can be seen that Seminole is projecting an emissions level that is reduced by approximately 96% over uncontrolled levels ((16-0.707)/16 = 95.6%). This level of control represents an extremely high level of performance for the unsubstantiated and unquantified benefits that have been attributed to co-control.

Using the USGS COALQUAL database that Seminole claimed to use for other pollutants to determine the uncontrolled rate would be 837 lbs/yr. Using EPA's uncontrolled AP-42 emissions factor, the annual emissions rate would be 1,026 lbs/yr. Using the controlled emissions factor, the rate would be 231 lbs/yr, exceeding the PSD significance threshold. 62 F.A.C. § 62-210.200(264)(a)(2). <u>See</u> Table 4. FDEP is obligated to use reliable and verifiable emissions estimates in issuance of permits and must, therefore, treat the Seminole 3 permit as a significant increase in mercury subject to PSD requirements.

Table 4 – Trace Metals for Seminole 3

	Claimed	Information Source	Actual	Information Source
Seminole 1& 2 Baseline	130 lbs/yr	Permit	99 lbs/yr	TRI reports
Seminole 1& 2 Reduction	46 lbs/yr	Permit		
Seminole 3 increase				
- uncontrolled*			1,026 lbs/yr	AP-42
- uncontrolled**			837 lbs/yr	USGS COALQUAL
-			1,339 lbs/yr	Florida DEP Study
- controlled	46 lbs/yr	Permit	231 lbs/yr	AP-42
Increase over baseline	Zero	Permit	231-1,026 lbs/yr***	AP-42

* AP-42 is the proper reference for estimation of emissions. Seminole appears to have selectively rejected this reference.

** Seminole claims to have used the USGS COALQUAL database to estimate emissions, a USGS report on mercury in coal based on this database gives a substantially higher value than reported by Seminole. Trends of Mercury Flow over the US with Emphasis on Florida, Janja D. Husar and Rudolf B. Husar, Florida Department of Environmental Protection Mercury Program, June 30, 2001

*** Seminole provides no basis for guarantee of performance and uses undocumented methods of estimating emissions. Using appropriate EPA emissions factors indicates that the emissions increase should be considered significant (greater than 200 lbs or 0.1 tpy under FAC)

C. FDEP must require enforceable mercury emissions reductions at Units 1 and 2 before making an emissions credit available to Unit 3.

As discussed above, the Draft Permit and supporting documents do not demonstrate that real and practically enforceable emissions reductions have occurred at Units 1 and 2 before allowing an emissions credit for Unit 3, as required by Florida regulations. 62-210.200(200)(f)(2); *see also* 1990 PSD Manual, p. A.38. FDEP should therefore require two years of CEMS/sorbent monitoring data to demonstrate such reductions before issuing a credit for Unit 3 and before allowing construction of equipment that will result in an emissions increase.

D. Seminole Unit 3 Mercury Emissions Are Subject to BACT.

Florida regulations define an increase of 0.1 tons per year of mercury (200 lbs/yr.) as a significant increase. 62 F.A.C. § 62-210.200(264)(a)(2). Using appropriate emissions calculations as shown above, mercury emissions from Seminole Unit 3 would be projected to increase, at a minimum, 231 lbs/yr, exceeding the PSD significance threshold. Moreover, the supposed reductions at Units 1 and 2 are neither demonstrable nor enforceable, and cannot be used to offset emissions from Unit 3. Seminole 3 should

I think the permit includes a enforceable Hg limit that would keep Unit 3 < 200 lb/year with compliance by CEMS.

therefore be subject to PSD review for mercury, including a BACT analysis. FDEP has improperly failed to require PSD review based on indirect and undocumented emissions factors and a vague expectation of co-control of mercury emissions as a result of benefits of other pollution control devices.

E. BACT For Mercury Emissions Is a Baghouse With Carbon Injection.

BACT for mercury must be specifically designed to control mercury emissions. Rather than requiring controls aimed at mercury, however, the Draft Permit relies on co-benefits of technologies designed to remove other pollutants. The mercury reductions that can be gained through technologies designed to reduce other pollutants are variable, and depend on fuel type, operating conditions, and numerous other factors. These technologies are therefore unreliable as a means to reduce mercury emissions.

Rather than relying on co-benefits, FDEP should require a baghouse with carbon injection to control mercury directly. Sorbent injection involves the introduction of a compound into the flue gas stream that adsorbs mercury and facilitates its capture by a downstream particulate control device. The sorbent most commonly applied for mercury removal is activated carbon. Permits for the following facilities mandate carbon or other sorbent injections as a specific mercury control technology: MidAmerican Energy (Iowa),[20] Newmont (Nevada),[21] Comanche (Colorado),[22] and Weston 4 (Wisconsin).[23] The use of sorbent injection technology at these facilities indicates that other states have determined that sorbent injection is capable of proven mercury removal.

F. FDEP Should Perform an Analysis of Control Efficiencies for Mercury Compounds as Part of the Evaluation for PM Controls.

As shown above, because the selection of the emissions rates and control efficiencies for mercury compounds are arbitrary and inconsistent with federal guidance, mercury emissions for Seminole 3 should have been treated as significant. Even if mercury emissions were not deemed significant, however, the evaluation of PM controls should have considered the superior ability of a baghouse to control mercury emissions.

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[20] Iowa DNR Air Quality PSD Construction Permit #03-A-425-P, issued 6/17/03, p. 1 (submitted herewith as Exhibit 24). For coal information, see Iowa DNR PSD Permit Review, Project 02-528, Plant #78-01-026, dated 4/21/03, p. 5.

[21] Nevada Bureau of Air Pollution Control, Class I Air Quality Operating Permit to Construct, 5/5/05, p. V-1 (Newmont). For coal information, see Nevada DEP Class I Application Review for Permit to Construct, Newmont TS Power Plant, 10/28/04, p. 1.

[22] Colorado Department of Public Health and Environment, Construction Permit – Boiler, Comanche Generation Station Permit #04PB1015, 7/5/05, p. 1.

[23] Wisconsin Department of Natural Resources, Air Pollution Construction Permit, Wisconsin Public Service Corporation – Weston Plant, 10/19/04, p. 12. For coal information, see Weston 4 Engineering Plan, 7/03, p. 11

The BACT analysis requires the agency to consider the technology's ability to reduce other pollutants. 62 F.A.C. § 62-210.200(39); *New Source Review Workshop Manual – Prevention of Significant Deterioration*, October 1990, p. B-50 ("The generation or reduction of toxic and hazardous emissions, including compounds not regulated under the Clean Air Act, are considered as part of the environmental impacts analysis. . . . The ability of a given control alternative to control releases of unregulated toxic or hazardous emissions must be evaluated and may, as appropriate, affect the BACT decision.") BACT for mercury compounds is the installation of a baghouse system with activated carbon injection. The baghouse should be BACT for PM also, because it has the ability to meet higher levels of mercury control.

The BACT analysis should also include the economic consideration that future retrofitting of the facility to remove the ESP controls and install baghouse controls will never be cost effective once the facility is constructed. If Seminole 3 fails to meet the proposed emissions limitations for mercury after the facility is constructed, a likelihood given the flawed analysis of mercury emissions, there will be no economically feasible way to reduce those emissions. It is therefore incumbent on FDEP to require the appropriate controls now.

V. FDEP MUST DENY THE PERMIT DUE TO SEMINOLE'S FAILURE TO PERFORM ADEQUATE BACT ANALYSES BECAUSE SEMINOLE FAILED TO EFFECTIVELY EVALUATE IGCC IN THE BACT ANALYSIS.

A BACT analysis for a coal fired power plant must include consideration of Integrated Gasification Combined Cycle ("IGCC") technology. IGCC is an inherently cleaner production process for the generation of electricity from coal that prevents the emissions of regulated pollutants into the atmosphere by removing contaminants such as sulfur and mercury from the hydrocarbons in the coal before the hydrocarbons are burned. IGCC is an established technology that is already "available" for commercial power production applications and at competitive costs, and within the meaning of 42 U.S.C. §7479(3). See e.g., Gregory B. Foote, Considering Alternatives: The Case For Limiting CO_2 Emissions From New Power Plants Through New Source Review, 34 ELR 10642, 10647 & n.54, 10659-60; see also Edward Lowe, General Manager, Gasification, GE Energy, GE's Gasification Developments, presented at Gasification Technologies 2005 Conference, San Francisco, CA, (October 10, 2005); Ron Herbanek, Mechanical Engineering Director, E-Gas and Thomas A. Lynch, Project Development Manager, ConocoPhillips, E-Gas Applications for sub-Bituminous Coal, presented at Gasification Technologies 2005 Conference, San Francisco, CA, (October, 11 2005).

Gregory Foote, Assistant General Counsel in the EPA's Office of Air and Radiation, notes that IGCC "is the most cost-effective technology for both limiting CO_2 emissions from coal-fired units now and for retrofitting CO_2 capture-and-storage technology in the future."[24] He suggests that, in light of the following factors, among others, it is unreasonable for a regulatory agency to issue a construction permit for a new coal-fired power plant without requiring IGCC as BACT (or Lowest Achievable Emission Rate "LAER"):

- "[T]he United States shares the general consensus of scientific opinion that CO_2 emissions constitute a clear and present danger to human health and welfare and the environment, both in the United States and throughout the world" Id. at 10664.
- Coal-fired power plants constitute "the largest category of CO_2 emitters" Id. at 10665.
- "Appropriate new source permit conditions can effectively mitigate the adverse environmental effects of CO_2 emissions from coal-fired power plants" Id.
- "IGCC is an environmentally superior technology for minimizing emissions of both NAAQS pollutants and mercury and other heavy metals" Id.
- "[A]ny newly constructed coal-fired plant will be in operation for many, many years, and this longevity should be taken into account." Id. at 10666.
- "[T]here is a high likelihood that mandatory CO_2 regulation will be adopted early in the life-span of any coal-fired plant constructed during the next several years." Id.
- "Given the likelihood of future CO_2 regulation, it would be unreasonable for NSR permitting authorities to simply ignore CO_2 emissions now" Id.

Other state agencies are requiring applicants proposing coal-fired electric power plants to consider IGCC in their BACT analyses.

- A Kentucky hearing officer ruled that the Environmental and Public Protection Cabinet "erred as a matter of law by concluding that it lacked authority to require TGC [the applicant] to include IGCC and CFB [circulating fluidized bed boilers] in its BACT analysis."[25]

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[24] Gregory B. Foote, Considering Alternatives: The Case for Limiting CO_2 Emissions From New Power Plants Through New Source Review, 34 ELR 10,642, 10,667 (July 2004).

[25] Sierra Club v. Environmental and Public Protection Cabinet, No. DAQ-26003-037 and DAQ-26048-037, Hearing Officer's Report and Recommended Secretary's Order, Aug. 9, 2005, at 176.

- More than three years ago, the New Mexico Air Quality Bureau directed Peabody Energy to include IGCC in its BACT analysis: "Please note that the AQB [Air Quality Bureau] has notified Peabody in its letter dated August 29, 2003 of its decisions that 'cost' cannot be the basis for technical infeasibility and that the Integrated Gasification Combined Cycle (IGCC) and the Circulating Fluidized Bed Boiler (CFB) are technically feasible and must be further evaluated in the BACT analysis."[26]

- Air agencies in nine other states have declared that IGCC is an available method for controlling air pollution from coal-fueled electric generating units.[27] The Northeast States for Coordinated Air Use Management (NESCAUM), representing the air quality programs from the states of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont, has stated repeatedly:

  > "IGCC is a highly efficient coal-based electrical generation technology that also results in substantial reductions in emissions of air contaminants, and therefore must, on a case-specific basis, "taking into account energy, environmental, and economic impacts and other costs," be considered in a BACT analysis for any new coal-fired power plant."[28]

- EPA advises states that it is prudent to have the applicant consider IGCC and CFB as part of the BACT analysis.[29]

Indeed, companies both in the U.S. and around the globe are building and operating IGCC plants. Two full scale commercial IGCC electric generating units are in operation in the United States: Tampa Electric Company's 262 MW unit at the Polk plant in Florida and Cinergy's 192 MW unit at the Wabash River plant in Indiana, which both rely on coal as a fuel source. Two other coal-based IGCC plants operate in Europe, NUON/Demkolec is a 253 MW plant in the Netherlands, and ELCOGAS in Spain is 298

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[26] Letter from Raj Solomon, Permits Section, Air Quality Bureau, to Ms. Diana Tickner, Peabody Energy, re Permit Application No. 2663 – Mustang Generating Station – Revised BACT Analysis, September 16, 2005, p. 1.

[27] Findings of Fact, Conclusions of Law, and Order in the Matter of the Air Quality Permit for the Roundup Power Project, Case No. 2003-04 AQ, Board of Environmental Review of the State of Montana (issued June 11, 2003, approved June 23, 2003); Amicus Brief of Northeast States for Coordinated Air Use Management in the Matter of the Air Quality Permit for the Thoroughbred Generating Station (Dec. 22, 2004); Amicus Brief of Northeast States for Coordinated Air Use Management in the Matter of the Air Quality Permit for the Elm Road Generating Station (Nov. 30, 2004).

[28] Letter from Northeast States for Coordinated Air Use Management to Texas Commission on Environmental Quality re Application of Sandy Creek Energy Associates (Dec. 5, 2005).

[29] E-mail from EPA Region 7 (Jon Knodel) to Susan Brown, Oct. 7, 2004.

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MW.[30] IGCC units can be constructed with multiple gasifiers to achieve unit availability at levels comparable to those of conventional baseload facilities. For instance, the Eastman Chemical plant in Kingsport, Tennessee has utilized a dual-gasifier design to produce chemicals from syngas and has experienced 98 percent availability since 1986.[31] ChevronTexaco claims that its new Standard Project Initiative Reference IGCC Plant achieves greater than 90% availability by using multiple gas trains.[32]

Worldwide there are 131 gasification projects in operation with a combined capacity equivalent to 23,750 MW of IGCC units.[33] An additional 31 projects are planned that would increase this capacity by more than 50 percent.[34] Although not all of these projects produce electricity from coal, they demonstrate widespread commercial application of gasification technology for fuel processing, one of two key components of an IGCC plant. The second component is a combined cycle electricity generating system, which is now commonplace for new natural gas fired power plants.

IGCC units are available from major well-known vendors. Coal gasification equipment is available from GE,[35] Shell, and Global Energy, while major turbine manufacturers, including GE and Siemens-Westinghouse, provide combined cycle generators designed to run on the synthesis gas produced by coal gasifiers. Engineers from Texaco, Jacobs Engineering, and GE have teamed up to offer a standardized IGCC design.[36] James Childress, the Executive Director of the Gasification Technology Council, provided testimony to the U.S. Senate Environment and Public Works Committee stating, "[g]asification is a widely used commercially proven technology."[37] At the same hearing, Edward Lowe, Gas Turbine-Combined Cycle Product Line Manager for General Electric Power Systems, stated that, "IGCC is inherently less polluting and

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[30] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Dec 2002, Table 1-7, page 1-26.

[31] Smith, R.G., Eastman Chemical Plant Kingsport Plant Chemicals from Coal Operations, 1983-2000, 2000 Gasification Technologies Conference.

[32] O'Keefe, L. and Sturm, K., Clean Coal Technology Options – A Comparison of IGCC vs. Pulverized Coal Boilers, presentation to the 2002 Gasification Technologies Conference, October 2002.

[33] Simbeck, Dale, SFA Pacific Inc. Gasification Technology Update, presented to the European Gasification Conference, April 8-10, 2002. The total capacity is based on output of synthesis gas. Many of these projects produce chemicals in addition to or instead of electricity.

[34] *Id.*

[35] On June 30, 2004, GE acquired the gasification business of ChevronTexaco

[36] O'Keefe, Luke, et al. A Single IGCC Design for Variable CO_2 Capture.

[37] Childress, James M., Statement Submitted for the Record, Senate Environment and Public Works Subcommittee on Clean Air, Wetlands and Climate Change, January 29, 2002.

more efficient than any other coal power generation technology."[38] Likewise, the National Coal Council, in a May 2001 report, confirms that IGCC is "viable, commercially available technology."[39] ChevronTexaco, in an October 2002 presentation, states that, "IGCC is a current viable choice for clean coal capacity."[40] And the Center for Energy and Economic Development (CEED) states that, "IGCC technology is available for deployment today."[41]

In addition, the following IGCC facilities are in various stages of development and permitting:

- Orlando Utilities Comm. & Southern Power Company has applied to FDEP for a permit to build a 285 megawatt IGG plant in Orange County, Florida.[42]
- In 2004, Steelhead Energy Co. filed a construction permit application with the Illinois Environmental Protection Agency for an IGCC unit that is scheduled to begin generating 545 MW of electricity from Illinois coal as early as 2009.[43]
- AEP signed an agreement with GE Energy and Bechtel Corp. to begin designing a proposed commercial-scale, 600-megawatt IGCC plant in Meigs County, Ohio. AEP plans to build at least one additional 600-megawatt or larger IGCC plant by 2013.[44] In its rate application to the Ohio Public Utilities Commission, AEP subsidiaries Columbus Southern Power Company and Ohio Power Company stated:

  "IGCC technology represents an advanced form of coal-based generation that offers enhanced environmental performance. The integration of coal gasification

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[38] Lowe, Edward. *Outlook on Integrated Gasification Combined Cycle (IGCC) Technology*. Senate Environment and Public Works Subcommittee on Clean Air, Wetlands and Climate Change, January 29, 2002.
[39] National Coal Council, Increasing Electricity Availability from Coal-Fired Power Plants in the Near Term, p. 20 (May 2001).
[40] Clean Coal Technology Options – A Comparison of IGCC vs. Pulverized Coal Boilers, Luke O'Keefe and Karl Sturm (ChevronTexaco), October 28, 2002, p. 8..
[41] See www.ceednet.org/fueling/investing.asp
[42] The draft permit for Orlando Utilities Comm. & Southern Power Company proposed IGCC unit is available at http://www.dep.state.fl.us/Air/permitting/construction/oucsouthern.htm
[43] Construction & Contracts, Power Engineering (Jan. 1, 2005); Steelhead's State Grant to Fund Coal Gasification Plant Design, Platt's Coal Outlook (Nov. 22, 2004); Steelhead Energy Awarded $2.5 Million Clean Coal Grant for Illinois Coal Gasification Project, Files Air Permit Application with Illinois EPA, PR Newswire (Nov. 11, 2004); Coke, Coal Gasification to Ultra-Clean Fuels, Power, Hydrogen Passes Turning Point; 'Polygen' Revolution Starts, Gas-to-Liquids News (Nov. 1, 2004).
[44] AEP Newsroom, AEP selects GE and Bechtel to design clean-coal power plant, Sept. 29, 2005. See also http://www.aep.com/about/igcc/AEP-igcc.htm.

technology, which removes pollutants before the gas is burned, with combined cycle technology results in fewer emissions of nitrogen oxide, sulfur dioxide, particulates and mercury, in addition to lower carbon dioxide emissions. The Companies believe that construction of an IGCC facility presents an economical and environmentally effective option for their long-term fulfillment of their POLR [Provider of Last Resort] obligation."[45]

- Cash Creek Generation LLC has applied to the Kentucky Division for Air Quality for a permit for a 677 megawatt IGCC merchant plant in Kentucky.[46]

- A partnership between the Eastman Chemical Company and the ERORA Group announced plans in February 2005 to pursue an IGCC unit, commencing commercial operations in 2009 or 2010.[47] As a result of this partnership, Christian County Generation LLC applied for a PSD permit for its Taylorville Energy Center, a proposed 677 megawatt IGCC plant in Illinois.[48]

- Several other companies also have announced plans to begin operating full-scale coal-fueled IGCC electric generating units.[49]

- AEP has filed PSD permit applications with the states of Ohio and West Virginia to build IGCC plants.

IGCC constitutes a fuel cleaning and innovative fuel combustion technique under the definition of BACT. NOx emissions from an IGCC plant are lower than those for modern coal-fired plants. Additionally, because sulfur is removed from the syngas before combustion, SO_2 emissions are less than half of that for a comparable traditionally-fired coal unit. Mercury and CO_2 control is also much easier for an IGCC plant than Pulverized

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[45] Application, In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Gasification Combined Cycle Electric Generating Facility, Before the Public Utilities Commission of Ohio, Case No. 05-376-EL-UNC (filed Mar. 18, 2005).
[46] Indiana Officials Oppose New Kentucky Plant, Utility E-Alert, #738, Aug. 26, 2005, at http://www.mcilvainecompany.com/UtilityFaxAlertSample.html.
[47] Eastman Studies Feasibility of Chemicals Co-Production, Press Release, Eastman Corporation, April 5, 2005.
[48] April 2005 PSD Permit Application for Taylorville, IL.
[49] CINERGY, Air Issues Report to Stakeholders (Dec. 1. 2004), at 2 (available at http://www.cinergy.com/pdfs/AIRS_12012004_final.pdf); "Industry Split on Type of Clean-Coal Technology Eligible for Government Support," Inside EPA (Aug. 4, 2004) ("Julie Jorgensen of Excelsior Energy . . . presented the details of a planned IGCC project in Minnesota, the Mesaba Energy Project, noting the company successfully pushed legislation in the state to encourage siting of IGCC plants and is pushing to install the technology in 2010 at a plant with with a 531 megawatt capacity for power generation.").

Does not seem prudent to force every new coal project to be an IGCC plant. The Seminole site is a existing PC-fired with existing unload, storage, and conveying systems that ~~allow~~ result ~~for~~ in substantial cost savings for the proposed new PC unit. IGCC is also inherently costly.

Coal or Circulating Fluidized Bed plants. See The Cost of Mercury Removal in an IGCC Plant at 1-2, US DOE, NETL, Sept. 2002. The Wisconsin Department of Natural Resources issued a permit for an IGCC unit in 2004, which included limits significantly lower than those for other coal-fired generation processes. Id. Moreover, EPA recognizes IGCC as an 'inherently low-polluting process/practice' for generating electricity, as indicated in a presentation given by EPA representatives. See, e.g., Robert J. Wayland, U.S. EPA Office of Air and Radiation, OAQPS, U.S. EPA's Clean Air Gasification Activities, Presentation to the Gasification Technologies Council Winter Meeting, January 26, 2006; U.S. EPA's Clean Air Gasification Initiative, Presentation at the Platts IGCC Symposium, June 2, 2005. EPA also found, after significant investigation, that IGCC is an effective method for controlling SO_2 emissions from the production of steam generated electricity.

> This can be accomplished by burning . . . a fuel that has been pre-treated to remove sulfur from the fuel . . . There are two ways to pre-treat coal before combustion to lower sulfur emissions: Physical coal cleaning and gasification. . . .. Coal gasification breaks coal apart into its chemical constituents (typically a mixture of carbon monoxide, hydrogen, and other gaseous compounds) prior to combustion. The product gas is then cleaned of contaminants prior to combustion. Gasification reduces SO2 emissions by over 99 percent.

U.S. EPA, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, 70 Fed. Reg. 9,706, 9,710-11 (February 28, 2005). Therefore, IGCC is BACT because it is a "clean fuel" option because it "will inherently have only trace SO_2 emissions because over 99 percent of the sulfur associated with the coal is removed by the coal gasification process." *Id.* at 9,715; In re Inter-Power of New York, 5 E.A.D. 130, 134 (EAB, 1994) ("[i]n deciding what constitutes BACT, the Agency must consider both the cleanliness of the fuel and the use of add-on pollution controls."). IGCC is also a "innovative fuel combustion technique," within the definition of BACT. Congress explicitly recognized IGCC as a "production process and available method[], system[] and technique," when enacting the BACT definition in 1977. The congressional history of the BACT definition includes the following discussion:

> Mr. HUDDLESTON. Mr. President, I send to the desk an unprinted amendment.
>
> The PRESIDING OFFICER. The amendment will be stated.
>
> The legislative clerk read as follows:
>
> The Senator from Kentucky (Mr. HUDDLESTON) proposes an unprinted amendment numbered 387: On page 18, line 15, after "ment" insert "or innovative fuel combustion techniques."

Mr. HUDDLESTON. Mr. President, the proposed provisions for application of best available control technology to all new major emission sources, although having the admirable intent of achieving consistently clean air through the required use of best controls, if not properly interpreted may deter the use of some of the most effective controls.

The definition in the committee bill of best available control technology indicates a consideration for various control strategies by including the phrase "through application of production process and available methods, systems, and techniques, including fuel cleaning or treatment." And I believe it is likely that the concept of BACT is intended to include such technologies as low Btu gasification and fluidized bed combustion. But, this intention is not explicitly spelled out, and I am concerned that without clarification, the possibility of misinterpretation would remain.

It is the purpose of this amendment to leave no doubt that in determining best available control technology, all actions taken by the fuel user are to be taken into account—be they the purchasing or production of fuels which may have been cleaned or up-graded through chemical treatment, gasification, or liquefaction; use of combustion systems such as fluidized bed combustion which specifically reduce emissions and/or the post-combustion treatment of emissions with cleanup equipment like stack scrubbers.

The purpose, as I say, is just to be more explicit, to make sure there is no chance of misinterpretation.

Mr. President, I believe again that this amendment has been checked by the managers of the bill and that they are inclined to support it.

Mr. MUSKIE. Mr. President, I have also discussed this amendment with the distinguished Senator from Kentucky. I think it has been worked out in a form I can accept. I am happy to do so. I am willing to yield back the remainder of my time.

123 Cong. Rec. S9434-35 (June 10, 1977) (debate on P.L. 95-95) (emphasis added).

A BACT analysis for a coal fired power plant must include a real consideration of IGCC technology. Seminole purportedly considered IGCC technology. However, Seminole did not actually adequately assess this technology. First, Seminole disregards the technology, stating that this is not a viable alternative because there are only two commercial plants operating in the United States. Air Permit Application, p. 56. As discussed in great detail above, this argument is not persuasive. In addition, Seminole states that it does not have to consider this technology under the BACT analysis because that would be "redefining" the source. Id.

Contrary to prevalent misconceptions, considering cleaner production processes—which is what IGCC is—does not "define" or "redefine" the source. Indeed, a supercritical pulverized coal plant and an IGCC plant are the same source: both are processes for creating electricity from coal-fired steam generation. In 1998 EPA adopted a nitrogen oxide limit as part of its new source performance standards that applied to all new electric generating units, regardless of whether it uses pulverized coal or IGCC combustion technologies. Revision of Standards of Performance for Nitrogen Oxide Emissions From New Fossil-Fuel Fired Steam Generating Units, 63 Fed. Reg. 49442 (September 16, 1998). On February 28, 2005 EPA proposed to revise its new source performance standards for the new electric generating units source category and, again, did not distinguish between pulverized coal and IGCC technologies. 70 Fed. Reg. 9706 (Feb. 28, 2005). In other words, EPA treats all electric generating units that burn coal (including gasified coal) as the same source category, and therefore as the same "source."

The "redefining the source" policy—which, incidentally, is a discretionary agency policy and not binding law—does not excuse a permitting agency from considering lower-polluting alternative production processes that produce the same product. Two decisions by the EPA Administrator explain the limited nature of the "redefining the source" policy. In Pennsauken County, New Jersey, Resource Recovery Facility the petitioner asked the EPA Administrator to deny a PSD permit to a municipal waste combustor and, instead, require the county to dispose of its waste by co-firing it with coal in existing power plants. PSD Appeal No. 88-8 at 10 (Adm'r, Nov. 10, 1988). The petitioner in Pennsauken County asked the EPA to order the applicant to engage in a different type of activity: electricity generation, rather than waste disposal. Not surprisingly, the Administrator determined that it would not "redefine the source" from a waste combustor to a power plant.

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

Pennsauken County at 10-11 (emphasis added). The Administrator subsequently reaffirmed the Pennsauken County decision and explained that "source," within the newly created "redefining the source" policy, refers to a source category.

> In Pennsauken, the petitioner was urging EPA to reject the proposed source (a municipal waste combustor) in favor of using existing power plants to co-fire a mixture of 20% refuse derived fuel and 80% coal. In other words, the petitioner was seeking to substitute power plants (having as a fundamental purpose the generation of electricity) for a municipal waste combustor (having as a fundamental purpose the disposal of municipal waste) . . ..

In re Hibbing Taconite Company, 2 E.A.D. at n. 12 (Adm'r 1989) (parentheticals original, emphasis added). Furthermore, after clarifying the "redefining the source" policy as only applying when requiring a cleaner production process would change in the "fundamental purpose," the Administrator specifically rejected the idea that requiring consideration of cleaner fuel constitutes "redefining the source" because the fundamental purpose, or source category, remains the same.

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

Id. at 842-843 (parenthetical original, emphasis added). In fact, the Administrator further explained that the "redefining the source" policy did not allow the permitting agency to blindly accept the source design, or fuel, proposed by the applicant. Id. Therefore, from its inception, EPA's "redefining the source" policy has merely stood for the concept that EPA will not require an applicant to abandon its intended purpose for some other industrial venture. This is a silly conclusion

It would be misapplying the EPA Administrator's policy to recreate the 'redefining the source policy' as the 'redesigning the source rule'—allowing the permit applicant to hold the BACT analysis hostage based on its chosen fuel, design, and combustion technology. By applying the "redefining the source" policy correctly, as described by the Administrator in Pennsauken and Hibbing, IGCC is not different "source" from a supercritical pulverized coal boiler. All are within the same source category. As in Hibbing, the redefining the source policy "has no merit in this case" because "EPA regulations define major stationary sources by their product or purpose (e.g., "steel mill," "municipal incinerator," "taconite ore processing plant," etc.), not by fuel choice." Hibbing at 842-43.

VI. TESTING PROVISIONS ARE NOT ADEQUATE TO ENSURE ENFORCEABILITY

The testing provisions in the Draft Permit are not adequate to assure that the emission limits that have been established to net out of NSR and to comply with BACT and other regulations will ultimately be met. The reasons for this inadequacy include the infrequency of monitoring and the inappropriateness of the monitoring method selected, as set out below.

A. Monitoring Frequency is Not Adequate to Ensure Compliance

The testing frequency in the Draft Permit is not adequate to assure continuous compliance, which is required for both BACT limits and potential to emit limits. The Draft Permit appears to require only a single initial stack test to determine compliance with the VOC limit; an initial stack test and a Title V renewal (every 5 years) test for fluorides; and an annual stack test for PM/PM10, SAM, and NH3. This is not adequate to ensure that Seminole 3 complies with the limits in the Draft Permit.

We note at the outset that the Permit is ambiguous as to VOC. The summary table on page 8 indicates only an initial stack test for VOC. Draft Permit at 8, Condition 10. However, the subsequent compliance testing section states that VOCs will be tested during each fiscal year. Draft Permit at 10, Condition 23. This discrepancy should be resolved. These comments assume only an initial stack test for VOCs.

Compliance with potential to emit and BACT limits should be demonstrated continuously. Based on EPA's guidance in the NSR Manual, the hierarchy for specifying monitoring to determine compliance is as follows: (1) continuous direct measurement of emissions where feasible; (2) initial and periodic direct measurement of emissions where continuous monitoring is not feasible; (3) use of indirect monitoring, e.g., indicator surrogate monitoring, where direct monitoring is not feasible; and (4) equipment and work practice standards where direct and indirect monitoring are not feasible. The Permit fails to follow this hierarchy because it allows periodic testing when continuous direct measurement is feasible, allows indirect monitoring and equipment and work practices when periodic testing is feasible, and specifies inadequate testing when periodic monitoring is appropriate.

The Permit requires infrequent periodic direct measurement (stack tests) to determine compliance with PM/PM10, VOC, HF, SAM, NH3, and Hg (no testing required until CEMS or sorbent trap monitoring system developed, Draft Permit at 9, Condition 17) emissions from Seminole 3. A stack test normally lasts only a few hours (two to six hours) and is conducted under ideal, prearranged conditions. Staged annual or other periodic testing tells one nothing about emissions during routine operation or startups and shutdowns on the other 364 days of the year or 8,750 plus hours.

In addition, these emissions can vary over a factor of 10 or more from hour to hour and from day to day. This variability is caused by process fluctuations and changes in fuel quality. An infrequent stack test will, therefore, not be representative of a source's ongoing emissions. Annual or other infrequent stack testing does not capture spikes caused by normal process operations.

For example, PM emissions from a utility coal-fired boiler can range from 0.01 to 1 pound per million British thermal units, depending upon the ash content of the coal being fired and the specific, upstream operations that are being carried out. Some routine process operations that occur only periodically, from daily to monthly, emit large amounts of VOCs, PM, and other contaminants. Emissions of PM, for example, substantially increase during soot blowing, which is rountiely used to clean deposits out of the boiler and to keep the SCR catalyst clean. Likewise, emissions of CO, VOC, and individual organic hazardous air pollutants, such as formaldehyde, substantially increase during startups and shutdowns, reaching concentrations high enough to cause acute health impacts in surrounding communities. Annual or other infrequent stack tests are almost never conducted during soot blowing, startups, or shutdowns, even though they are part of the routine operation of power plants.[50] These stack tests are, therefore, likely significantly underestimating emissions and are not sufficient to assure compliance with source emission limits.

Finally, it is well known that "[m]anual stack tests are generally performed under optimum operating conditions, and as such, do not reflect the full-time emission conditions from a source."[51] A widely used handbook on Continuous Emissions Monitoring ("CEMs") notes, with respect to PM_{10} source tests, that: "Due to the planning and preparations necessary for these manual methods, the source is usually notified prior to the actual testing. This lead time allows the source to optimize both operations and control equipment performance in order to pass the tests."[52]

Unless the monitoring requirements are changed, citizens cannot protect themselves against harmful emissions and local, state, and federal regulatory agencies cannot detect and cure violations of permit conditions. Indeed, even when citizens observe conditions that strongly suggest that a plant is violating its permit limits (e.g., plumes are visible at the stacks, odors are present, solids settle in their yards or homes, or

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[50] This is despite EPA guidance stating that stack tests should be conducted during soot blowing. EPA "Restatement of guidance on Emissions Associated with Soot-Blowing" (May 7, 1982).

[51] 40 Fed. Reg. 46,241 (Oct. 6, 1975).

[52] James A. Jahnke, <u>Continuous Emission Monitoring</u>, 2nd Ed., John Wiley & Sons, Inc., New York, 2000, at p. 241.

they experience adverse health effects), they are often powerless to prove such violations or to stop the illegal pollution because there is no monitoring data to support their claims.

1. FDEP Should Require CEMS for PM.

To assure that sources comply with emission limits, it is essential that monitoring be performed more frequently than is specified in the requirements discussed above. Particulate matter can be monitored with Continuous Emissions Monitors ("CEMs"). The record does not demonstrate that CEMS for these pollutants is not feasible. CEMS for particulate matter are feasible and have been required in several permits, including those issued to Longview, WV; Prairie State, IL; Iatan, MO; Trimble, KY, and Dalman Unit 4, IL. A PM CEMS should be required to determine compliance with the filterable PM/PM10 limit.

2. FDEP Should Consider Continuous Fourier Transform Infrared (FTIR) Monitoring for Sulfuric Acid Mist.

The Draft Permit contains an annual emission cap to allow Unit 3 to net out of PSD. Draft Permit at 6, Condition 2. Compliance with this cap is determined based on a single stack test each year. Draft Permit at 8, Conditions 10 and 14. Sulfuric acid mist emissions from coal-fired power plants are highly variable and depend upon numerous boiler and pollution control train operating parameters including fuel sulfur content, fuel iron content, time between soot blowing events, economizer outlet temperature, air preheater outlet temperature, SCR catalyst life, type of SCR catalyst, and voltage across ESP and WESP, among many others. Thus, it is important to monitor SAM more frequently than 3 hours per year, as required in the Draft Permit.

The Electric Power Research Institute (EPRI) has developed and demonstrated a method to continuously monitor SAM in the stack gases of coal-fired power plants. This technique, Fourier Transform Infrared spectroscopy or FTIR, is currently in operation at TVA Widows Creek.[53] Because Seminole is proposing to net out of PSD for SAM – the only such facility we are aware of that has proposed to net out of PSD review for SAM – we encourage FDEP to require Seminole to investigate this method and use it (or any other continuous SAM monitor) when it has been adequately demonstrated to show compliance with the proposed cap.

[53] Robert Spellicy, Richard Himes and John Pisano, Real-time Monitoring of SO3/H2SO4/NH3 in SCR Outputs, Proceedings of the 2006 Environmental Controls Conference, May 2006; Richard Himes, EPRI, Keeping an Eye on So3, Power Engineering, April 2006; EPRI, FTIR Monitoring of NOx, SOx, SO3, & H2S4, Slides, Proceedings of the 2006 Environmental Controls Conference, May 2006.

3. FDEP Should Require More Frequent Testing And Surrogates for VOC, Fluorides, and Sulfuric Acid Mist.

Where CEMs are infeasible, more frequent stack testing should be required, along with regular monitoring of key operating parameters or indicator pollutants that have been correlated with the applicable emission limit, e.g., CO as an indicator for VOC. The stack testing frequency in the Draft Permit is too low, ranging f rom only one initial stack test (VOC) to testing every 5 years (HF) to annual testing (SAM).

A typical stack test lasts about 3 hours. Over the 30 plus-year life of the facility, testing once for 3 hours would test only 3 hours out of 262,800 potential operating hours. Annual testing would test only 90 hours out of 262,800 potential operating hours or only 0.03 percent of the time. This testing frequency is inadequate to demonstrate continuous compliance with BACT limits and emission caps relied on to net out of PSD review. Thus, FDEP should require quarterly stack testing for the first two years, with reductions to lower frequency after compliance has been demonstrated. If any emission limit is thereafter exceeded, quarterly testing should resume until 2 years of compliance has been documented.

In addition to more frequent stack testing, surrogate parameters should be continuously monitored. A surrogate is an indicator parameter that is related to the parameter of interest. These are commonly used in PSD permits to demonstrate continuous compliance with limit on VOCs, HF, and SAM. See, for example, the Permit issued by Kentucky to Thoroughbred and Trimble. This is a valid approach for "[o]nly those parameters that exhibit a correlation with source emissions...." NSR Manual at H.6. Thus, we recommend that the Permit be modified to require the use of surrogates to determine continuous compliance with the proposed limits on VOCs (CO), HF (coal fluoride content), and SAMs (SO2 until a continuous monitor for SAM is installed) if a study demonstrates an acceptable correlation between the parameter and the surrogate. The relationship developed in the study should be validated annually by simultaneous source testing and coal sampling, allowing for the residence time through the facility. The Permit also should state that exceedance of the indicator range is a per se violation of the regulated pollutant.

B. The VOC Limit Is Not Enforceable

The Draft Permit sets a BACT emission limit for volatile organic compounds (VOCs) of 0.0034 lb/MMBtu and 16.7 lb/hr. Draft Permit at 8, Conditions 10 and 12. Compliance will be determined using EPA Method 25A and (optionally) EPA Method 18 (to deduct non-VOC methane emissions.) Draft Permit at Condition 12. The sampling frequency, which is not adequate, is discussed supra in Comment—. Further, the VOC limit and the test methods are mismatched.

To comply with the Clean Air Act, the owner of an emission source must set VOC emission limits based on a total VOC mass. 40 C.F.R. § 51.100(s). One cannot determine if VOC emissions are less than the PSD significance threshold or demonstrate that VOC emissions remain below this threshold unless one calculates VOCs on a total

Method 19 is used to convert methods 18 and 25A to mass-based units

Are there references in these methods

VOC mass basis.[54] The test methods listed in the Draft Permit do not reliably calculate VOCs on a total VOC mass basis.

The available VOC test methods in 40 C.F.R § 60—Methods 18, 25, and 25a—do not directly address the issue of reporting VOC emissions "as VOC." Method 25A, proposed as the main test method for Seminole, is designed to report total VOC as "carbon" meaning it assigns a mass to the sample based on the amount of carbon present, not the amount of VOC present. This test method also does not use isokinetic sampling. The stack gases from a coal-fired power plant equipped with FGD contain moisture droplets than entrain organic chemicals and act like particles in a gas stream. The equipment used in Method 25A does not adjust the sampling rate to match the uneven flow across the stack as is done, for example, during particulate testing. Thus, this method likely underestimates any VOCs contained in water droplets in addition to unreporting it as carbon.

Method 18, which is used to "correct" Method 25A, does measure VOCs on a total mass basis and should be used in preference to Method 25A. However, if the VOC stream consists of a large number of compounds and/or there are compounds in the VOC stream that individually are in low concentrations but, in the aggregate, consist of a significant portion of the total VOCs, Method 18 underestimates VOC mass. We believe this is likely for Seminole stack gases. Thus, we recommend that the Permit ~~be revised to~~ evaluate available methods to measure VOCs and select a method that complies with 40 C.F.R. § 51.100(s).

We note that the Draft Permit also specifies EPA Method 25, 25A, or 25B for CO. Draft Permit at 8, Condition 11(a). These methods measure VOCs, not CO. The method most commonly used to measure CO is EOA Method 10.

C. Initial Compliance Demonstration

The Draft Permit requires initial testing when firing 100% coal. Draft Permit at 9, Condition 22. However, the Draft Permit allows the combustion of two separate classes of fuel, 100% coal and a coal/pet-coke blend. Draft Permit at 7, Condition 9. The Permit does not require any testing of the coal/pet-coke blend. Thus, Permit conditions are not enforceable as to this fuel. Worst-case?

D. Ammonia Slip Testing

Ammonia slip from an SCR catalyst increases over time, reaching the design level at the end of the catalyst life. Thus, testing should occur at least at the end of the SCR catalyst life. The Draft Permit does not indicate when testing for ammonia would occur.

[54] Letter from Stephen D. Page, Direct, Office of Air Quality Planning and Standards, U.S. EPA, to Mary a. Gade, December 30, 2003. http://www.epa.gov/Region7/programs/artd/air/nsr/nsrmemos/gade.pdf#search=%22midwest%20scaling%20protocol%22.

However, the Draft Permit at 10 suggests it would occur following catalyst replacement, when ammonia is typically at its minimum, rather than just before catalyst replacement, when it is at its maximum. Draft Permit at 10, Condition 23. Thus, we suggest that the Permit be modified to specifically require ammonia testing near the end of the SCR catalyst life, or just before each layer of catalyst is changed out.

VII. THE EMISSION CAPS ARE NOT ENFORCEABLE

Seminole is "netting" out of, i.e., attempting to avoid, the requirements of Prevention of Significant Deterioration (PSD) for Hg, SO_2, SAMs, and NOx. This deal is consummated in the Draft Permit through a series of annual emission limits applicable to Units 1, 2, and 3. Draft Permit at 6, Condition 2. However, the proposed caps are not enforceable as a practical matter because they are expressed as annual averages in tons per year with no short-term averaging time, they are not enforceable during the first year of operation, and monitoring for Hg and SAM is not adequate to assure continuous compliance. FDEP should require additional permit conditions to ensure that the "netting" out actually occurs.

A limit on potential to emit, such as these, must be federally enforceable. A limit is federally enforceable if it is contained in a permit that is federally enforceable and if it is enforceable as a practical matter. See *U.S. v. Louisiana-Pacific Corp.*, 682 F. Supp. 1122, Civil Action No. 86-A-1880 (D.Colo. 1988). Practical enforceability means the source must be able to show continuous compliance with each limitation or requirement.[55]

The EPA has repeatedly concluded that "in accordance with the 1989 potential to emit policy, when an emission limit is taken to restrict potential to emit [as in this Permit], some type of continuous monitoring of compliance with that emission limit is required."[56] The permit must require continuous emission performance monitoring and recordkeeping where feasible.[57] NSR Manual, pp. H.10, I.3. The Draft Permit does not require continuous monitoring of either SAM or mercury.

[55] Memorandum from Terrell F. Hunt, Associate Enforcement Counsel, OECA, and John Seitz, Director, OAQPS, to EPA Regional Offices, Re: Guidance on Limiting Potential to Emit in New Source Permitting, June 13, 1989.

[56] Memorandum John B. Rasnic, Director Stationary Source Compliance Division, to David Kee, Director Air and Radiation Division, Re: Policy Determination on Limiting Potential to Emit for Koch Refining Company's Clean Fuels Project, March 13, 1992.

[57] *See, e.g.*, "Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act," from John Seitz, Director, OAQPS, to U.S. EPA Regional Offices, January 25, 1995, available at http://www.epa.gov/Region7/programs/artd/air/nsr/nsrmemos/ptememo.pdf; and "Guidance on Limiting Potential to Emit in new Source Permitting," from Terrell F. Hunt, Associate Enforcement Counsel, OECA, and John Seitz, Director, OAQPS, to U.S. EPA Regional Offices, June 13, 1989, available at http://www.epa.gov/Region7/programs/artd/air/nsr/nsrmemos/lmitpotl.pdf

In addition, the EPA has concluded that "[i]n order for emission limitations to be Federally enforceable from the practical stand point, they must be short term and specific so as to enable the Agency to determine compliance at any time."[58] Guidance by the U.S. EPA recommends that rolling annual averages be calculated on a daily basis unless not feasible. "EPA policy expresses a preference toward short term limits, generally daily but not to exceed one month."[59] EPA Region V has advised Ohio that "annual limits [referring to coating usage] should be rolled daily unless the company provides justification to why it is infeasible to monitor the limiting parameter daily."[60] See also guidance in Hunt 6/13/89[61] ("However, for these limitations [on production or operation] to be enforceable as a practical matter, the time over which they extend should be as short term as possible...") The emission limits on potential to emit are expressed only in tons per year with no short-term averaging time, as expressly required in all EPA NSR guidance. "Blanket emissions limits alone (*e.g.*, tons/yr, lb/hr) are virtually impossible to verify or enforce, and are therefore not enforceable as a practical matter." NSR Manual, p. c.4. The NSR Manual also indicates that limits must be written "in such a manner that an inspector could verify instantly whether the source is or was complying with the permit condition." NSR Manual, p. c.4.

Expressing the emission caps in only tons per year with no short-term averaging time has two ramifications. First, if an inspector shows up, he/she has no way to determine whether the source is in compliance on the spot. Second, you have to wait for an entire year before you collect enough data to determine compliance. Thus, the limits are not enforceable during the first year and are not practically enforceable over the long term. We thus recommend that FDEP express the caps as both instantaneous values (lb/MMBtu or ppm) and annual caps based on a rolling daily average. We also recommend that the Permit be modified to require continuous compliance with the Hg and SAM caps. Mercury CEMS are available. The Electric Power Research Institute (EPRI) has demonstrated the use of FTIR to continuously monitor SAM in coal-fired power plant stack gases.[62]

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[58] Memorandum from John S. Seitz to Air Management Division directors, Re: Clarification of New Source Review Policy on Averaging Times for Production Limitations, April 8, 1987.

[59] Memorandum from John S. Seitz to Directors, Re: Options for Limiting the Potential to Emit (PTE) of a stationary Source Under Section 112 and Title V of the Clean Air Act, January 25, 1992.

[60] Region 5 Air & Radiation Division Issue Paper, August 19, 1992, Proposed Paint Shop for GM Truck & Bus Group-Moraine Assembly Plant, Dayton, Ohio.

[61] Memorandum from Terrell E. Hunt to John S. Seitz, Re: Guidance on Limiting Potential to Emit in New Source Permitting, June 13, 1989.

[62] Robert Spellicy, Richard Himes and John Pisano, Real-time Monitoring of SO3/H2SO4/NH3 in SCR Outputs, Proceedings of the 2006 Environmental Controls Conference, May 2006; Richard Himes, EPRI, Keeping an Eye on So3, Power

A. The Permit Must Contain a Malfunction Restriction

The permit should specify that, if any pollution controls pertaining to sulfur dioxide and/or nitrogen oxides are not functioning or operating, or malfunctioning, then Seminole must shut down the entire unit. Otherwise the conditions assumed in the netting analysis (i.e., the addition of effective pollution control equipment) would not, in reality, exist.

B. The Permit Must Contain a Provision on the Timing of Controls and Emission Increases.

A requirement of netting is that emission reductions occur before a proposed emission increase. Therefore, FDEP should include a permit provision that requires Seminole to install the additional pollution controls for sulfur dioxide, nitrogen oxides, and sulfuric acid mist on Units 1 and 2 before commencing construction of Seminole 3.

A. The Permit Should Not Exempt Emission Limitations During Start-up and Shut-down.

Another reason to reject Seminole's request to exempt startup, shutdown, and/or malfunction from BACT limits is to preserve the netting out analysis. If FDEP were to grant Seminole's request to create a BACT exemption during startup, shutdown and/or malfunction, then the permit would allow for future emissions to exceed past actual emissions at Seminole 3 during those periods.

VIII. FDEP CANNOT EXEMPT EMISSIONS DUE TO STARTUP OR SHUTDOWN FROM BACT OR MODELING EMISSIONS

The draft permit for Seminole 3 states that "[e]xcess emissions resulting from startup, shutdown and malfunction of SGS Unit 3 shall be permitted providing: [] Best operational practices to minimize emissions are adhered to, and [] The duration of excess emissions from startup, shutdown and malfunction of SGA Unit 3 shall be minimized, but in no case exceed 60 hours during any calendar month." Seminole Draft Permit at 10. See also Condition 30 at 11 and Condition 38.h at 13. The draft permit indicates that this provision stems from Rule 62 F.A.C. § 210.700(5), (promulgated pursuant to 40 C.F.R. §60.8(c)).

However, unlike many of the NSPS emission limits, BACT emission limits must apply at all times, including startup, shutdown and malfunction. Emission limits defined as BACT under the PSD program are established under the state implementation plan and are intended to protect ambient air standards. The ambient air quality standards are to be met on a continuous basis. Thus compliance with the BACT limits must also be on a

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Engineering, April 2006; EPRI, FTIR Monitoring of NOx, SOx, SO3, & H2S4, Slides, Proceedings of the 2006 Environmental Controls Conference, May 2006.

continuous basis. For the same reasons, compliance with any of the emission limits used in the ambient air modeling analysis must also include emissions during startup, shutdown and malfunction.

Section 302(k) of the Clean Air Act expressly defines the term "emission limitation" as a limitation on emissions of air pollutants "on a continuous basis." Section 169(3) of the Clean Air Act, in turn, defines BACT as an "emission limitation." Accordingly, the Clean Air Act mandates that BACT continuously limit emissions of air pollutants. EPA's January 28, 1993 guidance memo entitled "Automatic or Blanket Exemptions for Excess Emissions During Startup, and Shutdowns Under PSD" specifically disallows automatic exemptions from BACT

Moreover, the permit allows excess emissions from startup, shutdown, and malfunction to continue for 60 hours unabated, because the total time is not limited to 2-hour increments, but rather can be averaged over a calendar month. Indeed, if a malfunction occurred at the end of a month, a 120-hour excess emissions period is conceivable. The permit level should be based on actual startup data from similar large units.

IX. PRECONSTRUCTION MONITORING SHOULD HAVE BEEN REQUIRED

Seminole should have collected site-specific, pre-construction meteorological data for use in their PSD Application modeling. Seminole, which is a major emission source of many air pollutants, should not be assessed for PSD increment compliance using non-site-specific meteorological data collected with none of the quality assurances necessary for air modeling data.[63]

Pre-construction meteorological data for projects that trigger PSD review is already being required for coal-fired power plants. Two recent projects in Nevada, Granite Fox Power (near Gerlach) and Newmont Nevada (Boulder Valley), have collected at least one year of pre-construction meteorological data. The data requirements, specific for input to air dispersion modeling for NAAQS and PSD increment analyses, are specified by the State of Nevada.[64] The State of Nevada Guidelines state: "Current on-site meteorological data are required for input to dispersion models used for analyzing the potential impacts from the air pollution sources at the facility."[65]

Even smaller air regulatory agencies have been requiring pre-construction meteorological data for many years. As part of their PSD program, the Santa Barbara

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[63] EPA, Ambient Monitoring Guidelines for Prevention 78 ntion of Significant Deterioration (PSD), EPA-450/4-87-07, May 1987, p. 55.
[64] Nevada Bureau of Air Pollution Control, Ambient Air Quality Monitoring Guidelines, May 4, 2000.
[65] *Id.*, p. 6.

County (California) Air Pollution Control district requires at least one-year of pre-construction air quality and meteorological monitoring.[66] The meteorological monitoring requirements are specified in a detailed protocol that implements their PSD Rule.[67] PSD sources in Santa Barbara County must collect site-specific hourly-averaged values for the following meteorological parameters:

- Horizontal wind speed and wind direction (both arithmetic and resultant)
- Horizontal wind direction standard deviation (sigma theta)
- Standard deviation of wind speed normal to resultant wind direction (sigma v)
- Vertical wind speed
- Vertical wind speed standard deviation (sigma w)
- Standard deviation of the vertical wind direction (sigma phi)
- Ambient air temperature
- Shelter temperature[68]

The Seminole air emissions are enormous and are released in a complex arrangement of point, area, and volume sources. Using an antiquated, low-quality, and non site-specific meteorological data set, for no other reason than to expedite the permitting process for the applicant, invalidates the entire air quality impact analysis. The PSD application should be denied because of this poor modeling practice, and not be resumed until Seminole has collected at least one year of site-specific meteorological data consistent with EPA's Meteorological Monitoring Guidance for Regulatory Modeling Applications.

X. SEMINOLE HAS NOT CONSIDERED REASONABLE ALTERNATIVES TO ITS PROPOSED COAL PLANT.

The Clean Air Act establishes the obligation on a permitting agency to consider, and an opportunity for the public to comment on, alternatives to major new sources of air pollution. For attainment areas, section 165(a)(2) prohibits construction of a new major emitting facility unless "a public hearing has been held with opportunity for interested persons * * * to appear and submit written or oral presentations on the air quality impact of such source, alternatives thereto, control technology requirements, and other appropriate considerations." 42 U.S.C. § 7475(a) (emphasis added).

Section 165(a), therefore, requires the public be given a reasonable opportunity to comment on four issues: (1) the air quality impact of such source"; (2) "alternatives" to "such source"; (3) "control technology requirements"; and (4) other appropriate considerations." 42 U.S.C. § 7475(a)(2). In combination with the permitting authority's obligation to respond to all reasonable comments, the permitting agency must consider

[66] Santa Barbara County Air Pollution Control District, Rule 803, Prevention of Significant Deterioration.
[67] Santa Barbara County Air Pollution Control District, Air Quality and Meteorological Monitoring Protocol for Santa Barbara County, October 1990.
[68] *Id.*, p. 57.

alternatives "to such source," including alternate sites, when the issue is appropriately raised by the public. Why else would Congress require a public hearing to consider "alternatives" to the proposed source? 42 U.S.C. § 7475(a)(2).

A permit applicant is not entitled to an air permit. Because the function of a single power 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. Power plants deserve particular scrutiny because of their tremendous size, longevity, capital and operating costs, demands on fuel suppliers and transmission lines, and adverse impacts. The threshold question in considering any prospective new power plant is why the plant should be constructed at all. Obviously, from an air pollution perspective it is preferable to rely on energy efficiency and renewable energy than to construct a new fossil-fueled power plant. In the absence of such analysis by the project applicant or another federal or state agency, this responsibility falls to FDEP.

A. FDEP Should Consider Whether to Build this Facility at all.

The BACT process presents one of the best opportunities to consider whether a new coal plant should be built at all. See 42 U.S.C. § 7475(a)(2). As described elsewhere in these comments, Seminole's proposal would be located is located close to three Class 1 areas. For each of these Class I areas, the existing Seminole power plants produces 95% of the pollution in these Class I areas. Under these circumstances, it would be arbitrary and capricious for the state to not consider whether there is a need for a new power plant in the first instance.

All indications are that Florida has ample electricity generating capacity. The CAA does not establish that Seminole has a right to build a new source of air pollution—particularly when it will significantly deteriorate two Class I Areas, cause harm to the residents of the area, and spread mercury pollution across Florida. In the absence of a demonstrated need, FDEP should not be granting Seminole a permit to add an additional unit. The costs simply far outweigh any alleged benefits of the proposed project.

B. FDEP Should Consider Energy Efficiency

There are multiple studies showing that aggressive implementation of energy efficiency measures in the residential, commercial and industrial sectors can eliminate the need for new electricity generation capacity.[69] These studies, in particular the Vermont study, demonstrate that energy efficiency measures are more cost-effective than building new power plants. Energy efficiency measures typically do not involve large amounts of air pollution.

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[69] See e.g., www.swenergy.org/nml/index.html;
www.efficiencyvermont.org/index.cfm?L1=292&L2=452&sub=bus;
www.energy.ca.gov/reports/2003-09-24_400-03-022D.PDF;
http://www.aceee.org/store/proddetail.cfm?CFID=569382&CFTOKEN=28344766&ItemID=377&CategoryID=7.

Based on the past success of implementing energy efficiency measures as well as projected population growth it would be irresponsible for the state to reject new power plants entirely. We could end up like CA

In 2004, the state of Florida enacted a commercial building energy efficiency standard precisely because avoiding the need for new power plants is good public policy. Similarly, under a mandate from Congress, EPA (and other agencies) regularly issue efficiency standards for new appliances. Florida and EPA clearly have broad authority to consider and implement energy efficiency measures.

For example, as part of the BACT and MACT analyses, FDEP can consider the opportunities for energy efficiency in Florida as a way to minimize the need and hence the pollution from Seminole's proposal. Similarly, a NEPA analysis must consider all reasonable alternatives to building a new coal plant, and thus should include meeting energy needs through energy efficiency measures.

FDEP must also consider whether additional energy efficiency measures can minimize and even eliminate altogether the need for Seminole's new generating unit. It is arbitrary and capricious for the state and federal agencies to not consider energy efficiency, prior to approving Seminole's proposal to build a giant coal-burning power plant.

We urge FDEP to consider whether additional energy efficiency measures can minimize and even eliminate altogether the need for Seminole's new generating unit.

C. FDEP Should Consider Alternative Sites and Cleaner Energy Sources.

There is existing coal plant...

The FDEP must consider alternate locations and alternate size facility to Seminole's proposal. Based on the proposed location—close to three Class I areas, Seminole's pollution presents a very serious threat to the environment, as well as causing "adverse" effects on public health. See infra for a detailed discussion of the public health impacts of the new unit. Furthermore, FDEP must also consider cleaner energy sources, such as wind generation. There is no demonstrated need for additional electric-generating capacity at the proposed site in Putnam County. It is arbitrary and capricious for the state and federal agencies to not consider alternative sites and cleaner energy options, such as wind-generation (or some combination of these alternatives), prior to approving Seminole's proposal to build a third generating unit.

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

The United States shares the general consensus of scientific opinion that CO_2 emissions constitute a clear and present danger to human health and welfare and the environment, both in the United States and around the world. This factual determination has been stated and restated in recent years with ever increasing clarity, certainty and authority. It is summarized, and adopted as the official position of the U.S. Government. See Climate Action Report 2002. The broad conclusions set out in this report reflect the resolution of an issue addressed by the 1970 Amendments to the CAA, which lists effect on the climate as a "welfare" effect of air pollution. Pub. L. No. 91-604 (1970).

Climate change is a serious global problem. There is general consensus of most scientists worldwide that increasing concentrations of greenhouse gases will lead to significant climate warming, shifts in precipitation patterns and rising sea levels, although the magnitude, timing, and regional patterns of these changes cannot be accurately predicted at this time.[70]

The primary contributors to climate change are greenhouse gases that absorb energy, retaining heat in the atmosphere and warming the planet.[71] The greenhouse gas of greatest concern is carbon dioxide (CO_2). The United States is the largest emitter of these gases, producing almost one-fourth of worldwide emissions of CO_2. U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001 – Final Version 2-1, Report EPA 430-R-03-004, April 2003.[72] Power plants alone account for one-third of total U.S. emissions of CO_2. Id. at Table 1-11.

The record in this case does not address CO_2 or other greenhouse gases (methane, nitrous oxide) that would be emitted from Seminole. However, such emissions are significant. Seminole would emit about 16 million tons per year of CO_2, assuming a capacity factor of 90% at Seminole 3.[73] This is substantially more than the amount of CO_2 released during the rush hour commute in Los Angeles.[74]

[70] David A. King, Climate Change Science: Adapt, Mitigate, or Ignore?, Science, v. 303, January 9, 2004, pp. 176-177.

[71] International Panel on Climate Change (IPCC), Summary for Policymakers: A Report of Working Group I of the Intergovernmental Panel on Climate Change, Geneva, 2001; National Research Council, Climate Change Science: An Analysis of Some Key Questions, 2001.

[72] U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001 – Final Version 2-1,
Report EPA 430-R-03-004, April 2003. Available at:
http://yosemite.epa.gov/OAR/globalwarming.nsf/content/ResourceCenterPulicationsGHGEmissionsUSEmissions Inventory2003.html

[73] This figure was calculated as follows:
Step 1: 99% of carbon in coal is converted to CO2. (AP-42.)
Step 2: Carbon content of coal at Seminole is 65%. (PSD Permit Application Table 2-1.)
Step 3: Maximum Unit 3 capacity is 2.8 million tons of coal per year, so 90% capacity is 2.52 million tons of coal per year. (PSD Permit Application, p. 5.)
Step 4: 2.52 million tons of coal/year x 65% carbon = 1.64 million tons of carbon/year.
Step 5: 1.64 tons of carbon/year x 99% conversion to CO_2 = 1.62 million tons of carbon/year.
Step 6: Carbon is oxidized to CO_2 and increases the molecular weight from 12 to 44. The ratio of 44/12 = 3.67.
Step 7: 1.62 million tons of carbon/year x 3.67 = 5.95 million tons of CO_2 per year.

Many new coal-fired power plants are proposed in Florida at a time when CO_2 emissions should be decreasing, not increasing. The proposed Seminole project would contribute to this dangerous trend. If Seminole's proposal and other coal-fired plants are built, they should be constructed to minimize CO_2 emissions and to facilitate future capture and safe storage of those emissions.

There can be no dispute that FDEP can regulate CO_2. The Florida administrative code, as approved into the Florida SIP, specifically requires that "the owner or operator of any facility or emissions unit which emits or can reasonably be expected to emit any air pollutant shall obtain an appropriate permit from the Department prior to beginning construction, . . . modification, or the addition of pollution control equipment." 62 F.A.C. § 62-210.300. The term "air pollutant" is defined to mean "Any substance (particulate, liquid, gaseous, organic or inorganic) which if released, allowed to escape, or emitted, whether intentionally or unintentionally, into the outdoor atmosphere may result in or contribute to air pollution." 62 F.A.C. § 62-210.200. The term "air pollution" is further defined to mean "[t]he presence in the outdoor atmosphere of the state of any one or more substances or pollutants in quantities which are or may be harmful or injurious to human health or welfare, animal or plant life, or property, or unreasonably interfere with the enjoyment of life or property, including outdoor recreation." 62 F.A.C. § 62-210.200. In addition, consistent with recent federal court action, Florida can also regulate CO_2 emissions under its public nuisance authorities.

We strongly urge FDEP to take the prudent step of requiring the applicant to mitigate its CO_2 and other greenhouse gas emissions. It is highly likely that Seminole will eventually have to control its CO_2 emissions under the Clean Air Act or public nuisance law. Twelve states (CA, CT, IL, ME, NJ, NM, NY, RI, VT, WA, NY, OR); 14 environmental groups; two cities (New York, Baltimore); American Samoa; Mariana Islands; and others have filed suit in federal court stating that EPA must regulate greenhouse gas emissions under the Clean Air Act. Specifically, the parties appealed the EPA's decision to reject a petition that sought to have the federal government regulate greenhouse gas emissions from new motor vehicles.[75] Further, the states of California, Connecticut, Iowa, New Jersey, New York, Rhode Island, Vermont and Wisconsin and New York City have filed suit in U.S. District Court in Manhattan under public nuisance law against the five largest CO_2 emitters in the United States. It is only a matter of time before reductions in global warming gases are mandated.

Step 8: Add 5.95 million tons of CO_2 per year from Seminole 3 to 10,032,384 tons of CO_2 per year from Seminole 1 and 2. (http://www.dirtykilowatts.org/index.cfm.) The result is approximately 16 million tons of CO_2 per year plant-wide.

[74] J.L. Sullivan and others, CO2 Emission Benefit of Diesel (versus Gasoline) Powered Vehicles, Environmental Science & Technology, v. 38, no. 12, 2004, pp. 3217-3223. Los Angeles traffic statistics at www.losangelesalmanac.com/LA/la13.htm.

[75] Commonwealth of Massachusetts, et al. v. U.S. EPA, No. 03-1361 (Consolidated with Nos. 03-1362-1368) U.S. Court of Appeals for the District of Columbia Circuit.

If the federal courts agree that greenhouse gases, such as CO_2, must be regulated under the Clean Air Act and nuisance law, such a decision would likely require the establishment of CO_2 emission limits for the Seminole Plant. Thus, the cost for controlling CO_2 emissions should be considered in the design of the plant. An IGCC plant, for example, would have lower CO_2 emissions than the proposed supercritical pulverized coal boiler technology. These benefits should be considered in the BACT analysis.

Mitigating CO_2 emissions from Seminole Generating Station is reasonable and should be required by your agencies. Four states currently regulate CO_2 emissions from the electric utility industry—Oregon, New Hampshire, Massachusetts, and Washington. The European Union also regulates CO_2 emissions and is in the process of implementing a CO_2 trading market, as are the New England states. CO_2 credits are trading in Europe at around $15 to $16 per ton.

Oregon has the oldest (1997), most stringent, and best developed CO_2 control program. It requires new power plants to offset CO_2 emissions by undertaking projects, reforestation, emission reductions, or by contribution to The Climate Trust, most recently at a rate of $0.85/ton. Washington, Massachusetts, and Montana are considering investing offset payments in The Climate Trust. Oregon currently limits CO_2 to a net emission rate of 0.675 pounds of CO_2 per kilowatt hour ("lb CO_2/kWh") for natural-gasfired base-load and all non-based-load plants.

Massachusetts requires that its six power plants meet a CO_2 limit of 1,800 lbs/MWH, which is about equal to a 10% reduction from a historic baseline of 1997, 1998, and 1999.[76] 310 CMR 7.29(5)(a)5. These requirements can be met with off-site reductions or sequestration. Trading and banking are also allowed. Plants can purchase reduction credits from outside the state. The regulations also require 1% CO_2 emission offsets for all new 100-MW or greater power plants.

New Hampshire requires that its three existing power plants reduce their annual CO_2 emissions to 10% below 1990 levels by December 31, 2006, through a cap and trade program. A lower cap can be imposed after 2010. Trading and banking of allowances is allowed. Rules are still under development

The CO_2 emissions from Seminole can be mitigated in a number of ways. These include redesigning Seminole to include non-fossil-fuel based, renewable energy generation, e.g., solar, wind; identifying and removing barriers to wind and solar development in Seminole's service region; converting Seminole to a natural-gas plant; implementing programs to capture CO_2 in forests and agricultural soils; implementing energy efficiency programs; implementing energy conservation and load management programs; capturing and using methane currently emitted from sewage treatment plants

[76] Massachusetts Bureau of Waste Prevention, Division of Planning and Evaluation, Statement of Reasons and Response to comments for 310 CMR 7.00 et seq.: 310 CMR 7.29 – Emission Standards for Power Plants, April 2001.

and coal mines; making payments to an independent, nonprofit organization that would find and contract for projects that offset CO_2, e.g., The Climate Trust, Oregon Forest Resource Trust; replacing inefficient wood-burning stoves with EPA-certified, wood-burning stoves, pellet stoves, and/or gas heaters, among many others.[77], [78]

In sum, the CO_2 emissions from Seminole should be mitigated to protect public health and welfare. We recommend that your agencies require that the applicant control CO_2 emissions by implementing a CO_2 mitigation program.

In the absence of other regulatory mechanisms, there is very substantial value added by considering the emissions of unregulated CO_2 when determining BACT for regulated pollutants, and in otherwise assessing the environmental impacts of a new coal-burning power plant. For example, the consideration of CO_2 would support the consideration of cleaner fuels (such as natural gas) and cleaner, more thermally-efficient process, such as IGCC. Moreover, consideration of ways to reduce CO_2 emissions would further support consideration of coal washing.

There are two additional reasons to support a conclusion that natural gas and/or IGCC should be seriously considered. First, any newly constructed power plant will be in operation for many decades. Second, there is a very high likelihood that mandatory CO_2 regulation will be adopted early in the lifespan of any coal-burning power plant constructed in the near future. Even President Bush has stated "I want to iterate today * * * that we're committed to reducing greenhouse gases in the United States." Joint Press Conference with President Bush and President Jose Maria Aznar of Spain (June 12, 2001). Some utilities are already factoring the inevitability of CO_2 regulation into their business plans. The prospect of future regulatory costs must be considered in order to determine the full costs of the options for minimizing emissions of currently regulated pollutants.

At the minimum, FDEP must consider emissions of CO_2 in its BACT (and MACT) analysis. The federal Environmental Appeals Board (EAB) has interpreted the definition of BACT as requiring consideration of unregulated pollutants in setting emission limits and other terms of a permit, since a BACT determination is to take into account environmental impacts.[79] Attached are three documents that discuss why CO2 impacts should be considered when permitting a new coal-fired power plant.

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[77] Oregon Office of Energy, State of Oregon, Energy Plan 2003-2005, December 2002; Wisconsin Department of Natural Resources (WDNR), Wisconsin Greenhouse Gas Emission Reduction Cost Study, Report 3. Emission Reduction Cost Analysis, Report AM-269-98, Volumes 1 and 2, February 1998.
[78] The Climate Trust 2002 Annual Report, 2002.
[79] See *In Re North County Resource Recovery Associates*, 2 E.A.D. 229, 230 (Adm'r 1986), 1986 EPA
App. LEXIS 14.

In *Considering Alternatives: The Case for Limiting CO_2 Emissions from New Power Plants through New Source Review,* a recently issued paper, Gregory B. Foote discusses the regulatory background to support consideration of CO_2 impacts when permitting a new source and, in particular, a new coal-fired power plant. This paper indicates that it is entirely appropriate to consider CO_2 emissions when evaluating environmental impacts under the new source review permit program, and the paper also provides suggested approaches for evaluating technologies in terms of CO_2 emissions.

A report issued last year entitled, Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value (attached hereto as Exhibit 1), prepared by Synapse Energy, Inc., explains why it is imprudent for decision-makers in the electric sector to ignore the cost of future carbon emissions reductions or to treat future carbon emissions reductions merely as a sensitivity case. The report concludes that treating carbon emissions as zero cost emissions could result in investments that prove quite costly in the future. Id. at 31-33. The report also identifies many information sources that regulatory agencies can utilize to make a reasonable assumption about the likely costs of meeting future carbon emissions reduction requirements. Id. at 17-29. See also Direct Testimony of David A. Schlissel and Anna Sommer, Synapse Energy, Inc., before the South Dakota Public Utilities Commission regarding Case No. EL05-022 (attached hereto as Exhibit 2).

If and when the Russian government ratifies the Kyoto Protocol, the Protocol will enter into force.[80] The first compliance period is 2008 to 2012. This development will put renewed pressure on the U.S. government and individual states to address the issue of CO_2 emissions from power plants. Ratification of Kyoto also will spur the next round of talks about minimizing the emissions of global warming. We urge the FDEP to not ignore these developments when considering Seminole's proposal.

XII. THE ENVIRONMENTAL IMPACTS ANALYSIS IS INADEQUATE.

The scope of the environmental impact analysis under the PSD program is akin to that required under the National Environmental Policy Act, 42 U.S.C. § 4321-4347. Congress exempted NSR permitting and other CAA actions from the requirements of NEPA on the basis that the CAA provides a "functional equivalent" of the analysis that would otherwise be required under NEPA. See Energy Supply & Environmental Condition Act §7(c)(1), 15 U.S.C. § 793(c)(1), see also, State ex re. Siegelman v. United States EPA, 911 F.2d 499, 505 (11th Cir. 1990) ("We see this express exemption [of CAA actions from NEPA] as Congress' way making more obvious what would likely to occur as a matter of judicial construction"). There are similar analyses required under MACT.

[80] Chadbourne & Parke, Project Finance NewsWire, June 2004, pg. 32.

A. FDEP Should Consider Impacts on Public Health

1. The Emission Limits for Particulate Matter are Not Protective of Public Health.

The allowable PM emissions will adversely impact public health. Particulate pollution from power plants has serious health impacts, leading to asthma attacks, heart attacks and to premature death. Particulate matter from power plants cuts short over 1,416 lives each year in Florida.[81] Sulfur emissions from the Seminole plant will lead to the formation of secondary particulate matter, which is also known to have serious health hazards.

A 2004 study by the Clean Air Task Force (CATF) has estimated that fine particle pollution from power plants shortens the lives of 1,416 Floridians each year. Fine particle pollution causes 155,908 lost works days, 1,367 hospitalizations and 28,321 asthma attacks each year, 1,219 of which are so severe that they require emergency room visits. *Id.* In the Jacksonville metropolitan area alone, fine particle pollution from power plants has the following health impacts:[82]

- 94 premature deaths each year
- 134 hearth attacks each year
- 13 lung cancer deaths
- 2,332 asthma attacks each year
- 82 hospital admissions each year
- 114 emergency room visits for asthma each year

The Seminole plant would add to these health effects as well as deteriorating public health in and around Putnam and St. Johns Counties.

The analysis for the Clean Air Task Force study was done by ABT & Associates, the same firm that has performed modeling for the EPA. This study provides the best evidence to date for fine particles' link to a broad range of effects leading to hospitalization and premature death. Previous studies had only established the link between fine particles and asthma-related hospital admissions. One such study, released in 1999, confirmed the relationship between increases in fine particle levels and increased hospital admissions for cardiovascular disease, pneumonia, and chronic obstructive pulmonary disease from power plants.

Several other important studies tie fine particle levels to emergency room visits. For example, fine particles were associated with emergency room visits for asthma in Seattle, Washington; Barcelona, Spain; and Steubenville, Ohio. Studies have linked air pollution with both hospital admissions and emergency room visits. The relative ease of

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[81] CATF, "Dirty Air Dirty Power," 2004. Metro area statistics can be found at http://www.cleartheair.org/dirtypower/docs/stateData/stateDataFL.pdf.
[82] CATF, "Dirty Air Dirty Power," 2004. Metro area statistics can be found at http://www.cleartheair.org/dirtypower/docs/stateData/stateDataFL.pdf.

availability of hospital admission data allows researchers to derive more complete estimates of health effects that require hospital visits. While these studies of hospital admissions and emergency room visits provide evidence that exposure to fine particles is directly associated with asthma attacks, researchers have also examined the relationship between air pollution and less severe asthma attacks that do not result in hospitalization. Studies in Denver, Los Angeles, and the Netherlands found that substantial increases in asthma attacks were linked with fine particle exposure.

Many other studies have also found a link between fine particle pollution and a whole range of well-known upper and lower respiratory symptoms including: deep, wet cough; running or stuffy nose; and burning, aching, or red eyes. Associations between fine particles and more general measures of acute disease have also been found. For example, one study evaluated the impact of fine particle levels on lost work days from workers calling in sick, an association that suggests an impact of air pollution on the U.S. economy, while other studies link particles and non-work restricted activity.

Extensive new research published over the past year finds that fine particles at levels routinely found in many U.S. cities may trigger sudden deaths by changing heart rhythms in people with existing cardiac problems. While further research is needed, these early studies are extremely important because cardiovascular disease is the number one killer in the United States, responsible for nearly half of all deaths. While heart rhythms in healthy persons remain largely unaffected by fine particle pollution, for those with existing heart disease fine particle exposures could have deadly consequences. The threat seems particularly acute for elderly people who have existing heart arrhythmia (a life-threatening condition of rapid, skipped or premature beats) or the combination of a weak heart and lung disease such as asthma. The studies suggest that people are dying within 24-hours after elevated particulate matter exposures. About a dozen major scientific studies in the United States, recently completed or underway, are turning up evidence of heart pattern changes in animals exposed in laboratories and in elderly people tested in nursing homes.

In the largest study of its kind, published in JAMA,[83] a group of 500,000 adults were followed for 16 years, PM2.5 monitoring data was collected, and 11 other co-founders compared. The study's objective was "To assess the relationship between long-term exposure to fine particulate air pollution and all-cause, lung cancer, and cardiopulmonary mortality." Id. The researchers conclusion: "Long-term exposure to combustion-related fine particulate air pollution is an important environmental risk factor for cardiopulmonary and lung cancer mortality." Id. In their results, they emphasized that "fine particulate and sulfur oxide-related pollution were associated with all-cause, lung cancer, and cardiopulmonary mortality. Each 10-µg/m3 elevation in fine particulate air

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[83] C. Arden Pope, Richard Burnett, Michael Thun, Eugenia Calle, Daniel Krewski, Kazuhiko Ito, and George Thurston, "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution," Journal of the American Medical Association Vol 287, No. 9, March 6, 2002, 1132-1141.
irc.ahajournals.org/cgi/reprint/109/21/2655

pollution was associated with approximately a 4%, 6%, and 8% increased risk of all-cause, cardiopulmonary, and lung cancer mortality, respectively. Measures of coarse particle fraction and total suspended particles were not consistently associated with mortality." Id.

"Associations have been found between day-to-day particulate air pollution and increased risk of various adverse health outcomes, including cardiopulmonary mortality. However, studies of health effects of long-term particulate air pollution have been less conclusive." Id.

The American Heart Association issued a Scientific Statement on Air Pollution and Cardiovascular Disease in June 2004 that focused on the association between cardiovascular morbidity and mortality and PM pollution.[84] The American Heart Association determined that there is a clear potential to improve the national public health and to substantially reduce cardiovascular morbidity and mortality by reducing PM levels to current EPA standards. The American Heart Association found that "...the existing body of evidence is adequately consistent, coherent, and plausible enough to draw several conclusions. At the very least, short-term exposure to elevated PM significantly contributes to increased acute cardiovascular mortality, particularly in certain-at-risk subsets of the population. Hospital admissions for several cardiovascular and pulmonary diseases acutely increase in response to higher ambient PM concentrations. The evidence further implicates prolonged exposure to elevated levels of PM in reducing overall life expectancy on the order of a few years." Id.

"On the basis of these conclusions and the potential to improve the public health, the AHA [American Heart Association] writing group supports the promulgation and implementation of regulations to expedite the attainment of the existing National Ambient Air Quality Standards. Moreover, because a number of studies have demonstrated associations between particulate air pollution and adverse cardiovascular effects even when levels of ambient PM2.5 were within current standards, even more stringent standards for PM2.5 should be strongly considered by the EPA."

Another study done in 2001 studied the relationship between particulate pollution and the triggering of myocardial infarction. This study found a 44% increase in heart attacks within 2 hours of PM2.5 exposure and 33% increase within 4 hours of PM2.5 exposure.[85] This study suggests that elevated concentrations of fine particles in the air may transiently elevate the risk of myocardial infarctions within a few hours and 1 day after exposure.

Seminole relies on the EPA's national ambient air quality standards for PM10 adopted in 1987. The EPA, in setting the national annual PM10 standard, did not consider

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[84] circ ahajournals.org/reprint/109/21/2655

[85] Annette Peters, PhD; Douglas W. Dockery, ScD; James E. Muller,MD; Murray A. Mittleman, MD, Dr PH, *Increased Particulate Air Pollution and the Triggering of Myocardial Infarction*, Circulation, June 12, 2001.

the carcinogenic potential of long-term exposure to PM10. In addition, in setting the national daily PM10 standard, the EPA did not consider the premature deaths resulting from short-term exposure to PM10.

The California Air Resources Board (CARB) demonstrated how EPA PM10 standards fail to protect public health.[86] A 1991 report by the California Air Resources Board (CARB) states that CARB uses a daily PM10 standard of 50 μg/m3, as opposed to the EPA's daily PM10 standard of 150 μg/m3, because EPA's standard does not address premature death. This report states that the annual EPA standard of 50 μg/m3 (CARB uses 30 μg/m3) is also not protective of public health since it does not address the carcinogenic potential of long-term exposure to PM10.

> In 1969, the Board established the standards for total suspended particulate matter or "TSP" which considered all the particles in the air. In December 1982, the Board rescinded the TSP standards and adopted standards for PM10. The PM10 standards are roughly equal in stringency to the previous TSP standards. However, the PM10 standards are more closely related to the actual effects of particles on human health because the PM10 standards address the particles small enough to reach the human lung. By expressing the standards in terms of PM10, the Board directed that control efforts focus on reducing the ambient particles that are most damaging to human health.
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> The Board adopted the PM10 standards to protect the public from the health effects of short-term exposure to ambient PM10 (the 24-hour PM10 standard) and long-term exposure (the annual PM10 standard). The 24-hour standard [set at 50 μg/m3] is based on studies which show that people with serious respiratory illnesses suffer increased death rates when exposed to increase concentrations of ambient PM10. The annual standard [set at 30 μg/m3 as an annual geometric mean] is based on studies which show that long-term exposure to PM10 causes decrease breathing capability and increased respiratory illness in susceptible populations such as children. The annual standard is also based on a consideration of the substances in PM10 that cause cancer.
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> The PM10 standards are expressed as a weight of PM10 particles per volume of air. There is no consideration of the size or the chemical make-up of the particles although these are important factors in terms of the health risks associated with PM10 (see previous section). The state PM10 standard is 50 micrograms per cubic meter. The state annual PM10

[86] Prospects for Attaining the State Ambient Air Quality Standards for Suspended Particulate Matter (PM10), Visibility Reducing Particles, Sulfates, Lead, and Hydrogen Sulfide: A Report to the Legislature, California Air Resources Board, Sacramento, CA, April 11, 1991 Bar Code: 5136 Call No: TD 883.1 P767 1991-2.

standard, calculated as the annual geometric mean of the 24-hour concentrations, is 30 micrograms per cubic meter.

The Board established both of the state PM10 standards as concentrations not to be exceeded.

In addition to the state PM10 standards, there are national PM10 standards. The EPA established the national PM10 standards during July 1987. The national 24-hour PM10 standard is 150 micrograms per cubic meter. The national annual PM10 standard is 50 micrograms per cubic meter, calculated as an annual arithmetic means.

Obviously, the state 24-hour PM10 standard is substantially more stringent than the national 24-hour standard. The adverse health effects the Board considered during the adoption of the state standard were premature death and respiratory illness. The populations at risk included individuals with prior respiratory health problems. The California Department of Health Services (the DHS) found that these serious health effects occur at PM10 levels well below what is now the national 24-hour PM10 standard.

In contrast, the national PM10 standard was based primarily on reversible decreases in respiratory function, and not premature death. The populations at risk were school aged children with normal health status, not necessarily individuals with prior respiratory health problems. The PM10 levels at which these health effects occurred were higher than those found by the DHS to cause premature death in sensitive segments of the population.

The results and analyses of studies published subsequent to the Board's adoption of the state 24-hour PM10 standard suggest strongly that the national 24-hour PM10 standard does not include any margin of safety, and therefore it does not adequately protect health.

The state 24-hour PM10 standard is primarily based on two studies. One study demonstrated increased illness in London patients with bronchitis. The other study showed that there were increased deaths in London during periods with high particle concentrations. The particle concentrations in both of these studies were reported as British Smoke and were mathematically converted to equivalent PM10 concentrations using a two-step conversion process. The British Smoke measurements were first converted to TSP concentrations, based on data from collocated instruments that measured British Smoke and TSP. (These instruments were operated in London.) The TSP concentrations were then converted to equivalent PM10 concentrations based on data that measured TSP and PM10. (These instruments were operated in the United States.) In adopting the state 24-hour PM10 standard, the Board also considered the recommendations of the California Department of Health Services.

The national 24-hour PM10 standard is based primarily on a study of decreased lung function in children living in Steubenville, Ohio. The study demonstrated that the decrease in lung function was closely associated with an increase in particle concentrations. The particle concentrations reported in this study were measured as TSP and were mathematically converted to equivalent PM10 concentrations. The conversion was based on collocated measurements of TSP and PM10 from Steubenville.

The state and national annual PM10 standard levels also differ. The state annual PM10 standards is based on studies which show adverse health effects associated with long-term exposure to particles at concentrations of approximately 50 micrograms per cubic meter and higher (ranging from about 50 to 177 micrograms per cubic meter). The state annual standard is also based on a consideration of the lifetime risk of cancer from exposure to the carcinogenic compounds present in PM10. The state annual PM10 standard is approximately equivalent to the previous state annual TSP standard, converted to PM10. In adopting the state annual PM10 standard, the Board relied heavily on the recommendations of the California Department of Health Services.

The national annual PM10 standard is based on studies of respiratory effects and illness in children and adults. The particle concentrations cited in these studies were measured as TSP and were converted to equivalent PM10 concentrations. The conversion used was based on collocated instruments that measured TSP and PM10. The EPA, in setting the national annual PM10 standard, did not consider the carcinogenic potential of long-term exposure to PM10.[87]

2. The Emission Limits for HAPs, including Mercury, are Not Protective of Public Health.

The EIS should analyze the environmental, health, and economic impacts of mercury pollution from Seminole. Coal-fired power plants are the single largest source of mercury emissions in the nation. Mercury emitted from coal plants, like Seminole, becomes methylmercury in the environment where it becomes toxic in even minute amounts. According to the FDA standard, it would only take 1 pound of methylmercury to contaminate 500,000 pounds of fish, which, when consumed by humans and wildlife increases their mercury levels. The U.S. EPA has found that 1 in 6 women has levels of mercury in her blood above the safe standard, putting her future children at risk for learning and behavioral problems associated with mercury poisoning.

[87] Excerpted from pp. 25-27 of Chapter IV - Suspended Particulate Matter (PM10) Section B. Ambient Air Quality Standards and the Health Effects of PM10 B.2. Standards for PM10.

As discussed below, see Section XIV, supra, the mercury analysis appears to understate the likely emissions from the plant. Along with the required BACT analysis, the Sierra Club requests modeling of the impact of mercury emissions on local deposition and accumulation in regional water bodies, and consideration of direct mercury controls to reduce mercury emissions that contribute to deposition and accumulation of mercury in the environment. In this consideration, the healthcare costs and future damages of lost productivity should be quantified.

A Mt. Sinai Medical School study has quantified the economic impacts of mercury exposure, specifically on lost productivity due to reductions in IQ.[88] The cost in lost productivity from methylmercury exposure (largely through the consumption of contaminated fish) is estimated to be $8.7 billion annually with $1.3 billion of this cost attributable to U.S. power plants. These costs, which measure only the costs from reduced productivity in adulthood due to reduction in IQ, do not consider the additional costs associated with IQ reduction, for example: poverty, out-of wedlock birth, low-weight births, welfare recipiency, dropping out of high school, and special education costs.

In addition to these costs on human health, mercury contaminated fish also risk the well-being of wildlife. The Wisconsin DNR has long studied the impact of mercury on the common loon, and discovered that loons have high mercury levels that contribute to low fecundity rates. Minnesota DNR is in the process of doing its own studies. FDEP should also consider the impact Seminole will have on wildlife by choosing not to install BACT-level mercury controls.

Mercury contamination of Florida waters is particularly severe. 100% of Florida waters are under a fish consumption advisory due to mercury contamination.[89] The release of mercury into the atmosphere is the primary cause of mercury contamination in Florida's waters. A comprehensive report of atmospheric mercury deposition in south Florida concluded, "Extensive monitoring of the Florida Everglades ecosystem has shown that the primary source of mercury loading is atmospheric deposition—over 95% of the mercury load to the Everglades each year comes from atmospheric deposition." Florida Dept. Envtl. Prot., Integrating Atmospheric Mercury Deposition with Aquatic Cycling in South Florida: An approach for conducting a Total Maximum Daily Load analysis for an atmospherically derived pollutant at 2 (Oct. 2002, Revised Nov. 2003).

The U.S. Environmental Protection Agency has identified coal-fired utility boilers as the largest source of domestic anthropogenic mercury emissions to the atmosphere and

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[88] *Protecting Children from Mercury Exposure Is Cost Effective,* Kathleen Schuler, MPH, and Christopher S Williams, MD, Institute for Agriculture and Trade Policy, March 8, 2005, available online at http://www.iatp.org/iatp/library/admin/uploadedfiles/Protecting_Children_From_Mercury_Exposure_is_C.pdf

[89] Florida's Department of Health, Florida Fish Consumption Advisories, http://www.myfloridaeh.com/community/fishconsumptionadvisories/

has noted a causal link between these releases and the presence of methylmercury in fish tissue.[90]

In addition to mercury, coal plants emit other hazardous air pollutants, including lead, arsenic, beryllium, nickel, and cadmium. The FDEP should at a minimum consider the impact of the above-mentioned HAPs (including mercury) in air modeling and in healthcare cost estimates.

B. FDEP Should Reevaluate the Solid Waste and Ash Management Plan

A proper solid waste and ash management plan for the forty plus year life of the plant is critical to avoid unnecessary environmental impacts from fugitive dust emissions and environmental contamination from leakage. The FDEP should thoroughly address the adequacy of the solid waste management plan, including the efficacy of the carbon burnout system and the capacity and integrity of the existing landfill. More information is needed regarding how much ash is recycled into Portland Cement, how much is landfilled and whether that landfill is properly engineered. These details are essential to analyze whether the waste disposal practices are adequate. In evaluating the facility's waste management plan, consideration should be given to the details of the storage plan, its location, the safety of long-term storage, a chemical analysis of the proposed waste (include what percentage of the ash is unsuitable for sale and the composition and risk of storage of this ash), and the impact of waste disposal on ground water supplies and nearby ecosystems. Additionally, the costs for cleaning up environmental contamination from poor ash management should be considered.

XIII. FDEP HAS FAILED TO COMPLY WITH THEIR ENVIRONMENTAL JUSTICE OBLIGATIONS.

Title VI has been interpreted by the United States Supreme Court to give federal agencies the authority to promulgate regulations precluding recipients of federal funds from engaging in activities that have a discriminatory effect or disparate impact. FDEP receives federal funds to administer its programs; therefore, FDEP must ensure that its activities, specifically a decision to issue an air permit to Seminole 3, does not have a discriminatory effect or disparate impact.

Sierra Club urges the FDEP to prepare an Environmental Justice assessment to determine if issuing this permit will have a disparate impact or discriminatory effect. FDEP should request an assessment or assess the health and well-being of the communities downwind of this facility and determine how this proposed expansion will impact those communities.

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[90] Gerald J. Keeler, *et al.*, *Sources of Mercury Wet Deposition in Eastern Ohio, USA*, Environ. Sci. & Technology at ___ citing *Mercury Study Report to Congress*, EP A-452/R-97-005; Office of Air Quality Planning and Standards, Office of Research and Development: Washington, DC, 1997).

The city of Palatka is directly downwind of the Seminole plant. Palatka certainly qualifies as an environmental justice community. The city of Palatka, in 2000, had a population 10,033. The population was 51.1% minority, had a median income for a family of $26,076, a per capita income of $11,351, 33.1% of the population lived under the poverty line, including 41.0% of those under the age of 18 and 19.6% of those over age 65. The city of Palatka's poverty level is three times the state of Florida's poverty level. When these statistics are compared with the same numbers of the state of Florida, there is no doubt that Palatka is an environmental justice community.[91]

The number of respiratory diseases in Putnam County, where Palatka is located, is significantly higher than the rest of the state. Every year, Putnam County has: 100 individuals diagnosed with lung cancer; 84 individuals die from lung cancer, 531 individuals are hospitalized for asthma, 470 individuals are hospitalized for chronic lower respiratory disease, and 58 individuals die from chronic lower respiratory disease. Although we do not know how many of these deaths and medical incidents were triggered from power plant pollution, the 2004 study by the Clean Air Task Force (CATF), discussed in detail above, indicates that there is probably a high correlation.

Palatka is already economically depressed and shoulders an unfair health burden when compared to the rest of the state. Seminole plans on selling the power generated at Seminole 3 in Georgia and throughout the state of Florida. Palatka is already economically depressed and shouldering more than its fair share of pollution. The city of Palatka and Putnam County should not have to bear the entire pollution load for this vast area.

FDEP should request an assessment of the impacts this proposed plant would have on this community using the information and tools available. This should include consulting with local and state health departments about the existing problems and ways to ensure there are no disproportionate impacts as a result of Seminole 3.

XIV. THE PERMIT FAILS TO ENSURE THAT SEMINOLE 3 WILL NOT CAUSE OR CONTRIBUTE TO AIR POLLUTION IN VIOLATION OF PSD INCREMENTS.

The PSD permitting process includes two mechanisms to ensure that pollution from a new plant or unit will not violate the Clean Air Act's air-quality standards. The first of those mechanisms is a requirement that there is no violation of an ambient air quality standard of PSD increment:

> the applicant shall perform the analysis in accordance with the provisions of 40 C.F.R. Part 51, Appendix W, adopted and incorporated by reference in Rule 62-204.800, F.A.C. For purposes of this demonstration, the

[91] For the state of Florida, in 2000, the population was 78.0 % minority, had a median income for a family of $45,625, a per capita income of $21,557, 12% of the population lived under the poverty line.

applicant shall use the most recent one-year period of meteorological data available and shall perform the analysis for each applicable pollutant and relevant averaging period.

> (a) The applicant shall demonstrate compliance with Rule 62-212.710(1)(a), F.A.C., by modeling all emissions units in the bubble by comparing in a single model run the difference between the allowable emissions in the existing permit(s) and the bubble baseline emissions for the proposed bubble. If at any receptor point the maximum concentration change has an increase above a significant impact level, as set forth in Rule 62-204.200, F.A.C., the applicant shall demonstrate compliance with ambient air quality standards and prevention of significant deterioration increments by performing an analysis which considers all emissions units at the facility and in the surrounding area according to the procedures of 40 C.F.R. Part 51, Appendix W.
>
> (b) The applicant shall demonstrate compliance with Rule 62-212.710(1)(b), F.A.C., by comparing the maximum concentration over the receptor grid of the allowable emissions in the existing permit(s) for all emissions units in the bubble with the maximum concentration over the receptor grid of the bubble baseline emissions for the proposed bubble.

62 F.A.C. § 62-212.710. Sub-section (a) of that regulation imposes a duty on the permit-applicant to demonstrate that the plant's emissions will not cause or contribute to a violation of the National Air-Quality Standards that are the basic benchmark of the Clean Air Act's overall regulatory scheme.

Sub-section (b) requires the permit-applicant to show that those emissions will not exceed the "maximum concentration," or "increment," of additional pollution in any area. Id. The increment is, in essence, a local air-quality standard, established on an area-by-area basis, serving to check pollution and protect public health in areas that have achieved the National Standards.[92] These local standards are established by measuring existing air quality in each area, and adding a statutorily-specified "maximum allowable increase" in pollution. 62 F.A.C. §§ 62-204.200; 62-204.220; 62-204.260. Air pollution in these areas is described as "consuming the increment," reflecting this method of adding a fixed "increment" of additional pollution to the pre-existing base-line. Because different areas have different base-line quantities of pre-existing air-pollution, and because the Clean Air Act allows for greater quantities of pollution to be added to some areas than others,[93] each specific area has its own, local increment-based air-quality standard (referred to herein as a "Local Air-Quality Standard").

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[92] See John-Mark Stensvaag, "Preventing Significant Deterioration Under the Clean Air Act: Baselines, Increments, and Ceilings – Part I," 35 Envt'l Law Rept'r 10,807, 10,810 (Dec. 2005).

[93] The amount of pollution allowed to be added to the air depends on the nature of the area. In "Class I" areas, such as National Parks, the increment is smaller than in other

Applicants perform modeling analyses in order to demonstrate that a source will not adversely impact NAAQS or a PSD increment. In general, modeling should identify worst-case impacts to *ensure* protection of NAAQS and PSD increments. Modeling reasonable worst case is especially important where there are no emissions limits on a source and there is uncertainty as to what emissions will be. In addition, for modeling to meaningfully ensure no adverse impacts, permitted emission levels must be modeled. Sources, having submitted a compliance demonstration, must be required to operate in the ranges of their compliance modeling demonstration.

The second mechanism protecting air-quality standards is a regulatory requirement that the FDEP publicly disclose the "the degree of PSD increment consumption expected" – that is, how much pollution the new plant will add in surrounding areas, and how close those areas will then be to a violation of their Local Air-Quality Standard. 62 F.A.C. § 62-210.350(2)(a)(3). This provides notice to "potential commenters [who] may have an interest in different areas to be impacted," including those concerned with the health impacts of air pollution as well as businesses planning industrial projects that might prove impossible once pollution exceeds the Local Air-Quality Standard. In re. Hadson Power 14 – Buena Vista, 4 E.A.D. 258, 272 (E.A.B. 1992). See Hancock Cty. v. U.S. E.P.A., 1984 U.S. App. LEXIS 14024, at *3 (6th Cir. 1984) (included in Addendum) (describing "first-come first-serve" method of permitting new sources of air pollution, until increment is consumed and no additional pollution can be authorized).

A. Seminole's Increment Consumption Analysis is Fatally Flawed.

There are serious flaws in Seminole's analysis of the impact of the Seminole plant's emissions on the Air-Quality Standards. Seminole submitted air quality modeling as required to ensure protection of NAAQS, but inappropriately modeled unenforceable permit limits to demonstrate compliance with SO2. SO2 emissions that Seminole has complete discretion to either implement or not implement were modeled. Seminole was only able to demonstrate compliance with SO2 PSD increment consumption for Seminole 3 under these fictional conditions.

In demonstrating the impacts of Seminole Units 1 and 2 on the Local Air Quality Standard for sulfur dioxide at nearby Okefenokee and Chassahowitzka National Wildlife Refuges, Seminole arbitrarily excluded all sources except the power plant itself – despite the acknowledged absence of any technical or legal basis to so limit the analysis. Seminole Electric Cooperative Request for Modification for Seminole Units 1 and 2, Appendix C, Air Quality Modeling Analysis. Even without those additional sources of air pollution, Seminole's analysis indicated that the increment would almost be exceeded for the Units 1 and 2 modification. See Table 3-6 (the Class I increment for sulfur

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areas in which the Act deems air quality to be of lesser concern. See 62 F.A.C. § 62-204.260.

dioxide for the 24-hour concentration is 5.00 μg/m^3 and the Seminole plant will contribute 4.99 μg/m^3). This would leave only 0.01 μg/m^3 for all future development in the area, including the new Unit 3.

Seminole applied to modify its permits for Units 1 and 2 at the Seminole Generating Station. CALPUFF modeling was used to predict increment consumption at the two nearest PSD Class I areas, the Okefenokee and Chassahowitzka NWA. Seminole Electric Cooperative Request for Modification for Seminole Units 1 and 2, Appendix C, Air Quality Modeling Analysis. Appendix C of the Seminole Air Permit Modification Application for Units 1 and 2, entitled Air Quality Modeling Analysis, presents the CALPUFF modeling results in comparison to the allowable PSD Class I increment. A summary of the maximum design concentrations, presented in Table 3-5, shows that the PSD Class I increment for sulfur dioxide is exceeded for the 3-hour averaging period at Okefenokee NWA and the Class I increment for sulfur dioxide is exceeded for the 24-hour averaging period at both Okefenokee and Chassahowitzka NWAs. Table 3-6 presents a breakdown of the total concentrations with the Seminole contributions to the total design concentrations.

The Class I increment for sulfur dioxide for the 3-hour averaging period at Okefenokee is 25 μg/m^3 and the increment consumption is 25.3 μg/m^3. Seminole's contribution to this increment consumption is 9.5 μg/m^3 or 37.5% of the total modeled value. The Class I increment for sulfur dioxide for the 24-hour averaging period at Okefenokee and Chassahowtzka is 5.00 μg/m^3 and the increment consumption would be 5.17 μg/m^3. Seminole's contribution to the 24-hour sulfur dioxide increment consumption is 4.99 μg/m^3 or 96.5% of the total modeled value. This demonstration was based on an emission rate of 0.67 lb/MMBtu for both Unit 1 and Unit 2.

Seminole attempted to demonstrate compliance with these Class I increments by looking only at Seminole's contribution to the increment consumption. This is patently wrong. In order to calculate increment consumption, one must look at all increment consuming sources. 40 C.F.R. Pt, 51, App. W, Section 8.2.1.1 (adopted and incorporated by reference in 62 F.A.C. § 62-204.800). Without analyzing all increment consuming sources there is no way to ensure that local air-quality standards are being met. When all increment consuming sources are modeled, violations of the Class I increment are predicted at the Okefenokee and Chassahowitzka NWAs. Therefore, Seminole has not demonstrated compliance with the allowable PSD Class I increment consumption to modify the air permit for Units 1 and 2. Despite these flaws with the increment compliance analysis, the draft modified permit for Units 1 and 2 has an emission rate for sulfur dioxide of 0.67 lb/MMBtu.

Seminole then applied for a PSD permit for Seminole 3. CALPUFF modeling was used to predict increment consumption at the nearest PSD Class I areas. This modeling did not use the enforceable emission rate for sulfur dioxide, but rather used an annual cap for sulfur dioxide. An annual cap is not an enforceable emission limit.[94] Specifically, the modeling was based on an emission rate for sulfur dioxide of 0.38 lb/MMBtu for both Unit 1 and Unit 2. However, this is not the emission rate contained in the draft permit for Units 1 and 2 (the permit limit is 0.67 lb/MMBTu). In addition, the draft modified permit for Units 1 and 2 was never modified to include this lower emission rate. Therefore, the sulfur dioxide emission rate for Units 1 and 2 that was used to demonstrate Seminole 3's compliance with Class I increments in the PSD Class I areas is not an enforceable permit limit that appears anywhere in any of the Seminole permits.

This is plainly wrong. Seminole 3's compliance demonstration is based on modeling of a completely unenforceable emission limitation, left to be implemented at the discretion of the permittee. In order to calculate increment consumption for a new unit, one must look at the actual emissions for the older units and not some arbitrary, unenforceable emission limit. There is no enforceable requirement that Seminole operate within these modeled limits. Thus, the applicant failed to demonstrate that the allowable emissions under the permit will not cause or contribute to a violation of the sulfur dioxide PSD increments.

This error is especially egregious because the only way that Seminole was able to (illegally) demonstrate compliance with the allowable PSD Class I increment consumption to modify the air permit for Units 1 and 2 was by unlawfully excluding all other increment consuming sources.

B. The Exclusion of Startup, Shutdown and Maintenance Emissions from the BACT limits fails to Demonstrate that the Allowable Emissions will Not Cause or Contribute to a Violation of NAAQS and PSD increments.

As set forth above, Seminole and FDEP erred by failing to establish emission limitations for periods of startup, shutdown and maintenance. This failure also constitutes a failure to demonstrate that the proposed unit will not cause or contribute to a violation of a PSD increment, as the emission rate used in the modeling is not required during periods of startup, shutdown and malfunction.

During startup, shutdown and malfunction, emissions of sulfur dioxide can increase because the pollution control technologies cannot be used. By omitting sulfur dioxide emissions from startup, shutdown and malfunction, Seminole has failed demonstrate protection and compliance with the sulfur dioxide PSD increment.

[94] Although the Unit 3 permit contains an annual SO_2 cap of 29,074 ton/yr for the three units, which is equivalent to 0.30 lb/MMBtu, the subject increments are 3-hour and 24-hour values. An annual cap is not enforceable as a practical matter and does not limit short-term emissions to those assumed in the increment modeling.

C. FDEP Failed to Provide Public Notice of the Degree of Increment Consumption at the Okefenokee and the Chassahowitzka National Wildlife Refuge Class I Areas.

Florida's Clean Air regulations require FDEP to provide public notice of "the degree of PSD increment consumption expected" as a result of the proposed Seminole 3. 62 F.A.C. § 62-210.350(2)(a)(3). The regulation's plain terms require disclosure to the "degree of PSD increment consumption expected" to occur. FDEP failed to provide public notice of the actual impact of the Seminole 3's sulfur dioxide pollution on the Local Air Quality Standard in the nearby Okefenokee and Chassahowtzka NWA Class I Areas. The FDEP, therefore, failed to provide adequate notice, hiding serious impacts to two of Florida's treasured public lands, as well as to industry in the surrounding area, and thereby violating the law.

CONCLUSION

For the reasons stated above, FDEP should deny the draft permit for Seminole 3. If FDEP does not deny the draft permit, then it should substantially revise the terms and conditions in accordance with the above comments. We respectfully request a copy of FDEP's response to comments on this draft permit, together with a copy of the final determination thereon.

Respectfully submitted,

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BEST AVAILABLE COPY

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

February 24, 2006

CERTIFIED MAIL – RETURN RECEIPT REQUESTED

Mr. James Frauen
Manager, Environmental Affairs
Seminole Electric Cooperative, Inc.
P.O. Box 272000
Tampa, Florida 33688-2000

RE: Seminole Electric Cooperative, Inc.
Seminole Generating Station Units 1 and 2
1070025-004-AC, PSD-FL-372

Dear Mr. Frauen:

The Bureau of Air Regulation received the above referenced application for processing on February 13, 2006. Included with the application was check no. 192302 for $7,500 to cover the permit processing fee. Since a $10,000 fee was submitted to the DEP Power Plant Siting Office to process this request, no additional fee is required for the PSD permit and your check is being returned with this letter. Please call me at 850/921-9505 if you have any questions.

Sincerely,

Patty Adams

Patty Adams
Bureau of Air Regulation

/pa
Enclosure
cc: M. Halpin

Department of
Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

February 17, 2006

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
P. O. Box 25287
Denver, Colorado 80225

RE: Seminole Electric Cooperative, Inc.
Seminole Generating Station Units 1 and 2
1070025-004-AC, PSD-FL-372

Dear Mr. Bunyak:

Enclosed for your review and comment is a PSD application submitted by Seminole Electric Cooperative, Inc. to authorize upgrades for Units 1 and 2 at the Seminole Generating Station in Putnam County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/921-9533. If you have any questions, please contact Mike Halpin, review engineer, at 850/921-9519 or 850/245-8993.

Sincerely,

Patty Adams

for Jeffery F. Koerner, P.E., Administrator
North Permitting Section

JFK/pa

Enclosure

cc: M. Halpin

Department of
Environmental Protection

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

Jeb Bush
Governor

Colleen M. Castille
Secretary

February 17, 2006

Mr. Gregg M. Worley, Chief
Air Permits Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303-8960

RE: Seminole Electric Cooperative, Inc.
Seminole Generating Station Units 1 and 2
1070025-004-AC, PSD-FL-372

Dear Mr. Worley:

Enclosed for your review and comment is a PSD application submitted by Seminole Electric Cooperative, Inc. to authorize upgrades for Units 1 and 2 at the Seminole Generating Station in Putnam County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/921-9533. If you have any questions, please contact Mike Halpin, review engineer, at 850/921-9519 or 850/245-8993.

Sincerely,

Patty Adams

for Jeffery F. Koerner, P.E., Administrator
North Permitting Section

JFK/pa

Enclosure

cc: M. Halpin

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

March 15, 2006

Mr. Gregg M. Worley, Chief
Air Permits Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303-8960

RE: Seminole Electric Cooperative, Inc.
Seminole Generating Station, Unit 3
1070025-005-AC, PSD-FL-375

Dear Mr. Worley:

Enclosed for your review and comment is a PSD application submitted by Seminole Electric Cooperative, Inc. for the construction of Unit 3 at the existing Seminole Generating Station in Palatka, Putnam County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/921-9533. If you have any questions, please contact Mike Halpin, Review Engineer, at 850/245-8993 or 850/921-9519.

Sincerely,

Patty Adams

for Jeffrey F. Koerner, P.E., Administrator
North Permitting Section

JFK/pa

Enclosure

cc: M. Halpin

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

March 15, 2006

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
P. O. Box 25287
Denver, Colorado 80225

RE: Seminole Electric Cooperative, Inc.
Seminole Generating Station, Unit 3
1070025-005-AC, PSD-FL-375

Dear Mr. Bunyak:

Enclosed for your review and comment is a PSD application submitted by Seminole Electric Cooperative, Inc. for the construction of Unit 3 at the existing Seminole Generating Station in Palatka, Putnam County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/921-9533. If you have any questions, please contact Mike Halpin, Review Engineer, at 850/245-8993 or 850/921-9519.

Sincerely,

Patty Adams

for Jeffrey F. Koerner, P.E., Administrator
North Permitting Section

JFK/pa

Enclosure

cc: M. Halpin

Jeb Bush
Governor

Department of Environmental Protection

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

Colleen M. Castille
Secretary

March 1, 2006

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. James R. Frauen, Manager of Environmental Affairs
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, FL 33618

Re: Request for Additional Information
Pollution Controls Upgrade Project
Seminole Generating Station, Units 1 and 2
DEP File 1070025-004-AC

Dear Mr. Frauen:

The Department is in receipt of your application dated February 13th which details several pollution control upgrades planned for Units 1 and 2. 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.

1. The Department notes that on Table B-4 entitled "PSD Netting Analysis", one PSD pollutant (CO) is expected to cause a BACT Review and every other PSD pollutant shows an increase. Please address the following issues relative to Table B-4:

   A. It is unclear which part of the project is responsible for the increase in CO emissions. Please provide specific information on where this increase originates. For example, if the applicant has deemed that the replacement burners will generate the additional CO, the Department will require support for this increase in the way of supplying detailed manufacturer burner specifications for the new as well as existing burners. Upon receipt of such information, the Department will be better positioned to evaluate whether the selected burners meet the Department's BACT Standard for CO emissions.

   B. Contemporaneous Emission Changes are defined in Rule 62-212.500(1)(e)3 as follows:

   3. Contemporaneous Emissions Changes. An increase or decrease in the actual emissions, or in the quantifiable fugitive emissions, of a facility is contemporaneous with a particular modification if it occurs within the period beginning five years prior to the date on which the owner or operator of the facility submits a complete application for a permit to modify the facility, and ending on the date on which the owner or operator of the modified facility projects the new or modified facility to begin operation.

   Also, Rule 62-210.200(34) defines Baseline Actual Emissions as follows:

   (34) "Baseline Actual Emissions" and "Baseline Actual Emissions for PAL" – The rate of emissions, in tons per year, of a PSD pollutant, as follows:
   (a) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding the date a complete permit application is received by the Department. The Department shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

The Department notes that based upon the above definitions, the Baseline Actual Emissions which are allowable for forming the basis of a netting analysis, cannot precede February 13, 2001; however, emissions for calendar year 2000 have been included within your application. The Department requests that the applicant indicate which 24-month period(s) following January 2001 is to be utilized for the baseline emission calculations of this project.

C. The following tables compare Departmental AOR records (TPY) of Unit 1 plus Unit 2 emissions to your TPY submittals:

	2001		2002		2003		2004		2005	
Pollutant	Dept.	SECI	Dept.	SECI	Dept.	SECI	Dept.	SECI	Dept.	SECI
SO2	29832	29832	24090	24090	27360	27360	26704	26704	???	31444
NO_x	20621	24408	18614	22170	22204	21560	19122	19967	???	23230
CO	2098	2609	2125	2592	3978	5400	2482	4552	???	5375
VOC	108	108	99	99	115	116	96	96	???	96
PM	431	498	664	721	1128	922	660	598	???	685
PM_{10}	431	498	664	721	1128	922	660	598	???	685

	2001 Plus 2002 Avg.		2002 Plus 2003 Avg.		2003 Plus 2004 Avg.		2004 Plus 2005 Avg.	
Pollutant	Dept.	SECI	Dept.	SECI	Dept.	SECI	Dept.	SECI
SO2	26961	26961	25725	25725	27032	27032	???	26704
NO_x	19618	23289	20409	21865	20663	20764	???	19967
CO	2111	2600	3052	3996	3230	4976	???	4552
VOC	104	104	107	108	105	106	???	96
PM	548	610	896	822	894	760	???	598
PM_{10}	548	610	896	822	894	760	???	598

In summary, after SECI has selected the baseline period(s) from the table above, any TPY values which are shaded, represent areas where the applicant is required to provide further supporting data for the higher than AOR values. If stack test data is utilized (e.g. CO, PM or H_2SO_4), the Department requires that certified summaries of all stack tests conducted during the subject calendar years be submitted; where AP-42 emission factors are utilized, the Department requires calculations along with the supporting data (i.e. annual heat input by fuel type, etc). Where CEMS data is utilized, the Department requires that the applicant provide supporting documentation from EPA's Acid Rain database demonstrating that the data matches. For the year 2005, the DARM/BAR is not in receipt of a copy of the AOR; hence no comparison can be made. Should SECI determine that 2004/2005 represents the baseline period, supporting data shall be required for all 2005 TPY emission data.

2. Please confirm the Department's understanding of the permit limits you are seeking for Units 1 & 2. The Department notes that in order to "carve out" emission reductions so as to make room for Unit 3, federally enforceable permit limits will need to be established for those pollutants where netting is desired.

Pollutant	Current Limit	Proposed Limit
SO2	1.20 lb/MMBtu – 30 day rolling	0.67 lb/MMBtu – 30 day rolling
NOx	0.60 lb/MMBtu - 30 day rolling	0.46 lb/MMBtu - 30 day rolling
PM/PM10	0.03 lb/MMBtu stack test	same
CO	NA	0.146 lb/MMBtu
VOC	NA	0.06 lb/ton coal
SAM	NA	0.096 lb/MMBtu

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.
FDEP/DARM
North Permitting Section

Hamilton Oven, DEP-SCO
Chris Kirts, DEP-NED
Scott Osbourn, Golder
PSRC c/o Pillsbury Winthrop Shaw Pittman, LLP