October 9, 2006

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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.

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[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:
  - control effectiveness (percent pollutant removed);
  - expected emission rate (tons per year);
  - expected emission reduction (tons per year);
  - energy impacts (Btu/kWh);
  - environmental impacts (other media and the emissions of toxic and hazardous air emissions); and
  - 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:

> [t]echnology 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.

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.

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.

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 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 both the applicant and FDEP are based on the less efficienty 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.

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".

[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).

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:

[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.

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.

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.

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.

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.

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.

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

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.

[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.[11]

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 http://www.fws.gov/wolfisland/index.htm.

[15] U.S. Fish and Wildlife Serv., Threatened and Endangered Species of Savannah Coastal Refuges, available at http://www.fws.gov/savannah/endangered.htm.

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</u> <u>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.).

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 (NO_X), 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 3 – Trace Metals for Seminole 3

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 x 10^9 lbs/yr coal burned, 5.58 x 10^9 x 0.15 ppmw = 837 lbs/yr mercury.

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

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[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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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). See 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* - uncontrolled** - - controlled	 46 lbs/yr	 Permit	 1,026 lbs/yr 837 lbs/yr 1,339 lbs/yr 231 lbs/yr	 AP-42 USGS COALQUAL Florida DEP Study 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 therefore be subject to PSD review for mercury, including a BACT analysis. FDEP has improperly failed to require PSD review based on incorrect 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). <u>See e.g.</u>, Gregory B. Foote, <u>Considering Alternatives: The Case For Limiting CO_2 Emissions From New Power Plants Through New Source Review</u>, 34 ELR 10642, 10647 & n.54, 10659-60; <u>see</u> <u>also</u> Edward Lowe, General Manager, Gasification, GE Energy, <u>GE's Gasification Developments</u>, 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]

[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.

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

[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.").

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.

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, Continuous Emission Monitoring, 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

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.

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.

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[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.

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[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] S*ee, 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

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[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.

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.

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. <u>See</u> <u>infra</u> 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. <u>See</u> <u>Climate Action Report 2002</u>. 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]

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[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

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[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.

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[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.
>
> 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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