Signing Authority

The Secretary of Veterans Affairs, or designee, approved this document and authorized the undersigned to sign and submit the document to the Office of the Federal Register for publication electronically as an official document of the Department of John R. Gingrich, Chief of Staff, Department of Veterans Affairs, approved this document on December 4, 2012, for publication.

List of Subjects in 38 CFR Part 3

Administrative practice and procedure, Claims, Disability benefits, Health care, Veterans, Vietnam.

Dated: December 5, 2012.

Robert C. McFetridge,

Director, Regulation Policy and Management, Office of the General Counsel, Department of Veterans Affairs.

For the reasons set out in the preamble, VA proposes to amend 38 CFR part 3 as follows:

PART 3—ADJUDICATION

1. The authority citation for part 3, subpart A continues to read as follows:

Authority: 38 U.S.C. 501(a), unless otherwise noted.

2. Revise § 3.310 by adding paragraph (d), to read as follows:

§ 3.310 Disabilities that are proximately due to, or aggravated by, service-connected disease or injury.

* * * * *

(d) Traumatic brain injury. (1) In a veteran who has a service-connected traumatic brain injury, the following shall be held to be the proximate result of the service-connected traumatic brain injury (TBI), in the absence of clear evidence to the contrary:

(i) Parkinsonism following moderate or severe TBI;

(ii) Unprovoked seizures following moderate or severe TBI;

(iii) Dementias (presenile dementia of the Alzheimer type and post-traumatic dementia) if manifest within 15 years following moderate or severe TBI;

(iv) Depression if manifest within 3 years of moderate or severe TBI, or within 12 months of mild TBI; or

(v) Diseases of hormone deficiency that result from hypothalamo-pituitary changes if manifest within 12 months of moderate or severe TBI.

(2) Neither the severity levels nor the time limits in paragraph (d)(1) of this section preclude a finding of service connection for conditions shown by evidence to be proximately due to service-connected TBI. If a claim does not meet the requirements of paragraph (d)(1) with respect to the time of manifestation or the severity of the TBI, or both, VA will develop and decide the claim under generally applicable principles of service connection without regard to paragraph (d)(1).

(3)(i) For purposes of this section VA will use the following table for determining the severity of a TBI:

Mild	Moderate	Severe
Normal structural imaging LOC = 0–30 min	Normal or abnormal structural imaging LOC >30 min and <24 hours	Normal or abnormal structural imaging. LOC >24 hrs.
AOC = a moment up to 24 hrs	AOC >24 hours. Severity based on other criteria.	
PTA = 0–1 day GCS = 13–15	PTA >1 and <7 days GCS = 9–12	PTA > 7 days. GCS = 3–8.

Note: The factors considered are:
Structural imaging of the brain.
LOC—Loss of consciousness.
AOC—Alteration of consciousness/mental state.
PTA—Post-traumatic amnesia.
GCS—Glasgow Coma Scale. (For purposes of injury stratification, the Glasgow Coma Scale is measured at or after 24 hours.)

(ii) The determination of the severity level under this paragraph is based on the TBI symptoms at the time of injury or shortly thereafter, rather than the current level of functioning. VA will not require that the TBI meet all the criteria listed under a certain severity level in order to classify the TBI at that severity level. If a TBI meets the criteria relating to LOC, PTA, or GCS in more than one severity level, then VA will rank the TBI at the highest of those levels.

(Authority: 38 U.S.C. 501, 1110 and 1131)

[FR Doc. 2012–29709 Filed 12–7–12; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R04–OAR–2010–0935, FRL–9760–5]

Approval and Promulgation of Air Quality Implementation Plans; State of Florida; Regional Haze State Implementation Plan

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing to approve certain Best Available Retrofit Technology (BART) and reasonable progress determinations included in a regional haze state implementation plan (SIP) amendment submitted by the State of Florida, through the Florida Department of Environmental Protection (FDEP), on September 17, 2012. These BART and reasonable progress determinations are for sources that are subject to the Clean Air Interstate Rule (CAIR) and were initially included in a July 31, 2012, draft regional haze SIP amendment submitted by FDEP for parallel processing and re-submitted in final form as part of the State's September 17, 2012, regional haze SIP amendment. In this action, EPA also proposes to find that Florida's September 17, 2012, amendment corrects the deficiencies that led to the proposed May 25, 2012, limited approval and proposed December 30, 2011, limited disapproval of the State's entire regional haze SIP, and that Florida's SIP meets all of the regional haze requirements of the Clean Air Act (CAA). EPA is therefore withdrawing the previously proposed limited disapproval of Florida's entire regional haze SIP and proposing full approval. This proposed action supplements the May 25, 2012, proposed limited approval action by superseding the proposed limited approval and replacing it with a proposed full approval. EPA will take final action on

the May 25, 2012, proposal, as supplemented herein, in conjunction with final action on today's proposal.

DATES: Comments must be received on or before January 9, 2013.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R04–OAR–2010–0935, by one of the following methods:

1. *www.regulations.gov:* Follow the on-line instructions for submitting comments.
2. *Email: R4-RDS@epa.gov.*
3. *Fax:* 404–562–9019.
4. *Mail:* EPA–R04–OAR–2010–0935, Regulatory Development Section, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street SW., Atlanta, Georgia 30303–8960.
5. *Hand Delivery or Courier:* Lynorae Benjamin, Chief, Regulatory Development Section, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street SW., Atlanta, Georgia 30303–8960. Such deliveries are only accepted during the Regional Office's normal hours of operation. The Regional Office's official hours of business are Monday through Friday, 8:30 to 4:30, excluding federal holidays.

Instructions: Direct your comments to Docket ID No. ''EPA–R04–OAR–2010–0935.'' EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit through *www.regulations.gov* or email, information that you consider to be CBI or otherwise protected. The *www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to EPA without going through *www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

Docket: All documents in the electronic docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, i.e., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the Regulatory Development Section, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street SW., Atlanta, Georgia 30303–8960. EPA requests that if at all possible, you contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to schedule your inspection. The Regional Office's official hours of business are Monday through Friday, 8:30 to 4:30, excluding federal holidays.

FOR FURTHER INFORMATION CONTACT: Michele Notarianni, Regulatory Development Section, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street SW., Atlanta, Georgia 30303–8960. Michele Notarianni can be reached at telephone number (404) 562–9031 and by electronic mail at *notarianni.michele@epa.gov.*

SUPPLEMENTARY INFORMATION:

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I. What Action is EPA Proposing to Take?

On March 19, 2010, FDEP submitted a regional haze SIP to address regional haze in Class I areas impacted by emissions from Florida and subsequently amended this SIP submittal on August 31, 2010. EPA proposed a limited disapproval of the Florida regional haze SIP on December 30, 2011, because of deficiencies in the regional haze SIP arising from the State's reliance on CAIR to meet certain regional haze requirements. *See* 76 FR 82219 (December 30, 2011). On May 25, 2012, EPA published an action proposing a limited approval of Florida's regional haze SIP to address the first implementation period. *See* 77 FR 31240. EPA's May 25, 2012, proposed rulemaking covered Florida's March 19, 2010, regional haze SIP and August 31, 2010, regional haze SIP amendment, as well as the State's April 13, 2012, draft regional haze SIP amendment which was submitted for parallel processing. The regional haze SIP, as amended on August 31, 2010, and April 13, 2012, addressed many of the regional haze requirements for Florida under CAA sections 301(a) and 110(k)(3). EPA proposed a limited approval, rather than a full approval, of Florida's regional haze SIP to the extent that it relied on CAIR.

On July 31, 2012, FDEP submitted an additional draft regional haze SIP amendment to evaluate BART and reasonable progress provisions for the remaining electric generating units (EGUs) not addressed in its April 13, 2012, draft SIP amendment.[1] On September 17, 2012, Florida submitted a final SIP amendment that consolidated the proposed changes in the April 13, 2012, and July 31, 2012, draft SIP amendments originally submitted to EPA for parallel processing. This

[1] In the draft SIP amendment provided on July 31, 2012, Florida addressed the 18 reasonable progress units and 11 facilities with BART-eligible EGUs subject to CAIR (a total of 20 EGUs) that were not covered by Florida's April 13, 2012, SIP amendment, and it also amended the SIP to remove Florida's reliance on CAIR to satisfy BART and reasonable progress requirements for the State's affected EGUs. Florida proposed these determinations in the July 31, 2012, proposed amendment and finalized them in the September 17, 2012, final SIP amendment. The facilities addressed for reasonable progress are: City of Gainesville Deerhaven unit 5; Florida Power & Light (FPL) Manatee units 1, 2; FPL Turkey Point units 1, 2; Gulf Power Company Crist unit 7; Lakeland Electric C.D. McIntosh unit 3; JEA Northside/St. Johns River Power Park (SJRPP) units 3, 16, 17; Progress Energy Florida (PEF) Anclote units 1, 2; PEF Crystal River units 1, 2, 3, 4; and Seminole Electric Cooperative, Inc. (SECI) units 1, 2. The facilities addressed for BART are: City of Tallahassee—Arvah B.Hopkins Generating Station (unit 1); PEF Anclote Power Plant (units 1, 2); PEF Crystal River Power Plant (units 1, 2); FP&L Manatee Power Plant (units 1, 2); FPL Martin Power Plant (units 1, 2); FPL Turkey Point Power Plant (units 1, 2); Gulf Power Company Crist Electric Generating Plant (units 6, 7); Gulf Power Company Lansing Smith Plant (units 1, 2); JEA Northside SJRPP (unit 3); Lakeland Electric C.D. McIntosh, Jr. Power Plant (units 1, 2); and Reliant Energy Indian River (units 2, 3).

submittal addressed BART and reasonable progress requirements for certain EGUs where Florida had relied on CAIR to meet BART and reasonable progress regulatory requirements for these units and made changes to the text of its SIP to remove reliance on CAIR for Florida sources. On November 29, 2012 (77 FR 71111), EPA took final action fully approving the unit-specific BART determinations for all of the sources addressed by EPA's May 25, 2012, proposal.

EPA's December 30, 2011, proposed limited disapproval of Florida's regional haze SIP was based on the State's initial reliance on CAIR to satisfy both BART requirements and the requirement for a long-term strategy (LTS) sufficient to achieve the state-adopted reasonable progress goals (RPGs). *See* 76 FR 82221. As mentioned above, Florida's September 17, 2012, SIP amendment replaced reliance on CAIR to satisfy the BART and reasonable progress requirements for its affected EGUs with case-by-case BART and reasonable progress control analyses. To the extent that the SIP's underlying emissions inventories and projections of emissions reductions from upwind states are affected by the implementation of CAIR, the recent decision by the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) in *EME Homer Generation, L.P.* v. *EPA,* No. 11–1302 (D.C. Cir., August 21, 2012) (*EME Homer*) to vacate the Cross-State Air Pollution Control Rule (Transport Rule) and keep CAIR in place ensures that any emissions reductions associated with CAIR are sufficiently permanent and enforceable for purposes of this action (see section III.C, below, for further discussion).

EPA is now proposing to take two related actions. First, EPA is proposing to approve the remaining BART and reasonable progress determinations in Florida's September 17, 2012, regional haze SIP amendment not previously addressed in EPA's November 29, 2012, final action.[2] Second, EPA is proposing to find that Florida's September 17, 2012, SIP amendment corrects the deficiencies that led to the December 30, 2011, proposed limited disapproval and the May 25, 2012, limited approval of the State's regional haze SIP and that the regional haze SIP as a whole now meets the regional haze requirements of the CAA. EPA is therefore withdrawing the previously proposed limited disapproval of Florida's entire regional haze SIP and proposing full approval. This proposed action supplements the May 25, 2012, proposed limited approval action by superseding the proposed limited approval and replacing it with a proposed full approval. EPA will take final action on the May 25, 2012, proposal, as supplemented herein, in conjunction with final action on today's proposal.[3]

II. Summary of Florida's September 17, 2012, Regional Haze SIP Amendment

Florida's regional haze SIP identifies 31 EGUs subject to CAIR for assessment for reasonable progress and 23 sources with BART-eligible EGUs that initially relied on CAIR emissions limits for sulfur dioxide (SO_2) and nitrogen oxides (NO_X) to satisfy their obligation to comply with BART requirements. CAIR was promulgated by EPA in 2005 to require significant reductions in emissions of SO_2 and NO_X from EGUs and thus to limit the interstate transport of these pollutants and the ozone and fine particulate matter (PM) they form in the atmosphere. *See* 76 FR 70093. The D.C. Circuit initially vacated CAIR, *North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir. 2008), but ultimately remanded the rule to EPA without vacatur to preserve the environmental benefits provided by CAIR, *North Carolina* v. *EPA,* 550 F.3d 1176, 1178 (D.C. Cir. 2008). Subsequent to the remand of CAIR, and in response to the court's decision, EPA issued the Transport Rule to address interstate transport of NO_X and SO_2 in the eastern United States. *See* 76 FR 48208 (August 8, 2011). On August 21, 2012, the D.C. Circuit issued a decision to vacate the Transport Rule. In that decision, it also ordered EPA to continue administering CAIR ''pending the promulgation of a valid replacement.'' *EME Homer Generation, L.P.* v. *EPA,* No. 11–1302 (D.C. Cir., August 21, 2012).[4]

EPA has recognized that prior to the CAIR remand, the State's reliance on CAIR to satisfy BART for NO_X and SO_2 for affected CAIR EGUs was fully approvable and in accordance with 40 CFR 51.308(e)(4). In addition, as explained above, CAIR remains in place until EPA develops a suitable replacement. However, the Florida facilities with EGUs that previously relied on CAIR to satisfy their BART and reasonable progress obligations for SO_2 and NO_X will eventually not be subject to CAIR. FDEP also recognized that CAIR's replacement might not satisfy the regional haze requirements for Florida. Accordingly, FDEP initiated an effort to reassess BART and reasonable progress for all of the facilities that had relied on CAIR to meet regional haze obligations. In its April 13, 2012, draft regional haze SIP amendment, FDEP addressed 13 of the 31 EGUs subject to reasonable progress analysis and 12 of the 23 facilities with BART-eligible EGUs. In its July 31, 2012, draft amendment, Florida addressed the remaining 18 reasonable progress units and the remaining 11 facilities with BART-eligible EGUs subject to CAIR (a total of 20 EGUs). The State's September 17, 2012, amendment finalized these BART and reasonable progress determinations addressed in its April 13, 2012, and July 31, 2012, draft SIP amendments, and on November 29, 2012, EPA finalized full approval of the BART determinations addressed in the April 13, 2012, amendment. *See* 77 FR 71111. Table 1 lists the 18 facilities subject to reasonable progress analysis that EPA is acting on in this notice and Table 2 lists the 11 BART-eligible EGUs that EPA is acting on in this notice.

TABLE 1—FACILITIES SUBJECT TO REASONABLE PROGRESS ANALYSIS WITH UNIT(S)[5] ALSO SUBJECT TO CAIR

[Italicized units are also subject to BART]

City of Gainesville—Gainesville Regional Utilities (GRU) Deerhaven (Unit 5).
FPL—Manatee (Units *1, 2*).
FPL—Turkey Point (Units *1, 2*).
Gulf Power Company—Crist (Unit *7*).
Lakeland Electric—C.D. McIntosh (Unit 6).
JEA—Northside/SJRPP (Units *3,* 16, 17).
PEF—Anclote (Units *1, 2*).
PEF—Crystal River (Units *1, 2,* 3, 4).
SECI—(Units 1, 2).

TABLE 2—BART-ELIGIBLE FACILITIES WITH UNIT(S) SUBJECT TO CAIR

City of Tallahassee—Arvah B. Hopkins Generating Station (Unit 1).
PEF—Anclote Power Plant (Units 1, 2).
PEF—Crystal River Power Plant (Units 1, 2).
FPL—Manatee Power Plant (Units 1, 2).
FPL—Martin Power Plant (Units 1, 2).
FPL—Turkey Point Power Plant (Units 1, 2).
Gulf Power Company—Crist Electric Generating Plant (Units 6, 7).
Gulf Power Company—Lansing Smith Plant (Units 1, 2).
JEA Northside—SJRPP (Unit 3).
Lakeland Electric—C.D. McIntosh (Units 1, 5).
Reliant Energy Indian River—Indian River Plant (Units 2, 3).

[2] See footnote 1, above.

[3] Today's action does not affect the November 29, 2012, final action fully approving the BART determinations for the sources addressed by EPA's May 25, 2012, proposal.

[4] That decision is not yet final as the mandate has not issued and on October 5, 2012, EPA filed a petition asking for rehearing *en banc.*

[5] Emissions unit numbers reflect the numbering system used by FDEP, which may differ from the facilities' numbering methodology.

III. What is EPA's analysis of Florida's September 17, 2012, regional haze SIP amendment?

A. Facilities Subject to Reasonable Progress Analysis

As discussed above, a portion of the State's September 17, 2012, regional haze SIP amendment addresses 18 of the EGUs subject to CAIR and a reasonable progress analysis. Ten of these emissions units are also subject to BART review under the Regional Haze Rule (RHR): FPL—Manatee Units 1, 2 ; FPL—Turkey Point Units 1, 2; Gulf Power Company—Crist Unit 7; JEA Northside—SJRPP Unit 3; PEF—Anclote Power Plant Units 1, 2; and PEF—Crystal River Power Plant Units 1, 2. As discussed in the July 1, 2007, memorandum from William L. Wehrum, Acting Assistant Administrator for Air and Radiation, to EPA Regional Administrators, EPA Regions 1–10, entitled *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program* (''EPA's Reasonable Progress Guidance''), EPA believes that it is reasonable to conclude that any control requirements imposed in the BART determination also satisfy the reasonable progress-related requirements for source review in the first implementation period since the BART analysis is based, in part, on an assessment of many of the same factors that must be addressed in making source-specific reasonable progress determinations. Therefore, Florida conducted individual reasonable progress control reviews only on the remaining eight EGUs at five facilities: GRU Deerhaven (Unit 5); Lakeland Electric—C.D. McIntosh (Unit 6); JEA—Northside/SJRPP (Units 16, 17); PEF—Crystal River (Units 3, 4); and SEC (Units 1, 2).

The CAA and RHR require that states consider the following factors and demonstrate how these factors were taken into consideration in making source-specific reasonable progress determinations: Costs of compliance; time necessary for compliance; energy and non-air quality environmental impacts of compliance; and remaining useful life of any potentially-affected sources. CAA section 169A(g)(1); 40 CFR 51.308(d)(1)(i). The results of FDEP's reasonable progress analyses for the eight remaining EGUs are summarized below by facility, followed by EPA's assessment.

1. GRU Deerhaven

GRU's Deerhaven Emissions Unit 5 is a nominal 251 megawatt (MW) coal-fired EGU. SO_2 emissions are currently controlled with a dry flue gas desulfurization (FGD) system designed to achieve a target outlet SO_2 emissions rate of 0.12 pound per million British Thermal Units (lb/MMBtu). This dry FGD came on-line in 2009, providing reductions in SO_2. Prior to the installation and operation of the FGD, FDEP identified this unit for a reasonable progress analysis because its reasonable progress source selection metric of emissions (Q) divided by distance (d) from the Class I area or ''Q/d'' (i.e., 2002 SO_2 emissions in tons/distance in kilometers (km))[6] ratio in 2002 was greater than 50 (6,969 tons/112.2 km = 62.12), the Q/d value used by Florida to determine which sources would be subject to a reasonable progress analysis. Due to the addition of the dry FGD, FDEP has issued a federally enforceable permit condition that limits SO_2 emissions to 5,500 tons per year, resulting in a maximum Q/d value of 49.0. Thus, no further analysis of this source is required for this implementation period.

2. PEF—Crystal River

Units 3 and 4 at PEF's Crystal River plant are fossil fuel-fired EGUs, each rated at 760 MW. SO_2 emissions are controlled with wet FGD systems that came on line in 2009 (Unit 4) and 2010 (Unit 3) and are designed to reduce emissions by 97 percent. Wet FGD systems are considered by FDEP to be the top-level SO_2 emissions control system for coal-fired boilers such as Units 3 and 4, and the SO_2 emissions from these units are limited to 0.27 lb/MMBtu, based on a 30-day rolling average, through a federally enforceable permit. The source considered the potential for additional SO_2 reductions through the use of lower sulfur western coal but found that it would not be cost-effective, as discussed below.

Cost of Compliance: The source is already incurring the cost of the new wet FGD systems as they were installed in 2009 and 2010, before the reasonable progress evaluation. While lower sulfur coal is potentially available from the Powder River Basin (PRB), PRB coal is a sub-bituminous coal with unique combustion characteristics that would require additional operational modifications to ensure continued safe and reliable unit performance. Moreover, the transportation of this coal from Wyoming to Florida would be cost prohibitive and produce secondary environmental impacts.

Time Necessary for Compliance: Wet FGD is already installed and operating; therefore, no additional time for compliance is necessary. Installing additional add-on controls for PRB firing would take, at a minimum, several years due to PEF's need to continue operating the units as base-load to supply reliable electric power to its customers.

Energy and Non-Air Quality Environmental Impacts of Compliance: Since Florida considers wet FGD as the top-level control and it is already installed, no additional energy or non-air quality environmental impacts would occur. The impacts from the use of lower sulfur PRB coal could potentially include: increased water usage, additional solid waste, secondary emissions caused by fuel transportation, and additional energy usage for control.

Remaining Useful Life: The source anticipates that Emissions Units 3 and 4 will continue to operate for another 28 years.

Conclusion: After considering the four reasonable progress factors for PEF-Crystal River, FDEP determined that the existing wet FGD systems at the current, permitted emissions limits satisfy the reasonable progress requirements for this implementation period.

3. SECI

SECI Units 1 and 2 are solid fuel, dry-bottom, wall-fired units with a maximum heat input of 7,172 million British Thermal Units per hour (MMBtu/hr) generating 736 MW each. Units 1 and 2 are currently authorized to burn coal as the primary fuel but are also authorized to burn a blend of coal and petroleum coke with up to a maximum of 30 percent by weight petroleum coke. The maximum sulfur content of the petroleum coke may not exceed 7.0 percent by weight on a dry basis (2.3 times the coal sulfur content of 3.0 percent by weight). Units 1 and 2 are each equipped with a wet FGD to control SO_2 emissions.

Cost of Compliance: FDEP has determined that wet FGD technology provides the highest SO_2 removal efficiencies for coal-fired boilers. As such, no lower level control option was reviewed. However, certain upgrades are available to improve the FGD systems to achieve 95 percent removal efficiency, and while not quantified, the company has agreed to incur the costs to achieve this removal efficiency. In addition to the FGD controls for SO_2, the facility is equipped with electrostatic precipitators (ESPs) for control of PM; low NO_X burners and Selective Catalytic Reduction (SCR) for NO_X control; and an alkali injection system to control emissions of sulfuric acid mist. The wet FGD controls were installed in 1984 and

[6] Florida's development and use of the Q/d metric is discussed in EPA's May 25, 2012, proposal at 77 FR 31251.

upgraded in 2010 to comply with CAIR and other air regulatory programs (e.g., the Utility Mercury Air Toxics Standards (MATS) rule). Following these upgrades, the allowable SO_2 emissions rate for Units 1 and 2 was reduced from 1.2 to 0.67 lb/MMBtu on a 30-day rolling average basis. The FGD control systems on Units 1 and 2 currently achieve approximately 92 percent SO_2 removal, and SECI proposes to make additional changes to Units 1 and 2 to achieve a minimum SO_2 removal efficiency of 95 percent or, alternatively, to achieve an equivalent SO_2 emissions rate of no more than 0.25 lb/MMBtu on a 30-day rolling average basis for both units.

SECI is presently evaluating available options to achieve the proposed 95 percent SO_2 removal efficiency or the emissions limit identified above including, but not limited to, further modifications to the internal components of the FGD, increasing limestone recirculation rates, and increased used of dibasic acid. SECI will complete its evaluation and provide FDEP with the details of the selected option by March 1, 2013. The amount of time required to implement the selected option and achieve the proposed SO_2 emissions limits will depend on the option's design and whether construction is required. However, within one to three years following option selection, but no later than March 1, 2016, SECI will achieve either the proposed SO_2 emissions limit or the removal efficiency requirements. The applicable limits and final compliance date are included in a federally enforceable permit.

Time Necessary for Compliance: Compliance with the 95 percent SO_2 removal efficiency or the alternate emissions limit of 0.25 lb/MMBtu SO_2 will be achieved by March 1, 2016.

Energy and Non-Air Quality Environmental Impacts of Compliance: There are no additional energy or non-air quality environmental impacts since the FGD system is already installed and operating.

Remaining Useful Life: These units are anticipated to operate indefinitely.

Conclusion: After considering the four reasonable progress factors for SECI Units 1 and 2, FDEP has determined that the existing wet FGD SO_2 control systems with upgrades to achieve a minimum SO_2 removal efficiency of 95 percent or, alternatively, an equivalent SO_2 emissions rate of no more than 0.25 lb/MMBtu on a 30-day rolling average basis for both units are adequate to satisfy the reasonable progress requirements for this implementation period. In addition, the State has removed the option to burn petroleum coke from the facility's federally enforceable permit.

4. Lakeland Electric C.D. McIntosh

Lakeland Electric C.D. McIntosh's Unit 6 is a nominal 364 MW fossil fuel-fired EGU that fires coal and up to 20 percent petroleum coke, low sulfur fuel oil (<0.5 percent sulfur by weight), high sulfur fuel oil (>0.5 percent sulfur by weight), and natural gas or propane. Unit 6 is subject to a federally enforceable permit condition that limits SO_2 emissions to: 0.80 lb/MMBtu for liquid fossil-fuel firing (3-hour average, 40 CFR 60 subpart D); 1.20 lb/MMBtu for solid fossil-fuel firing (3-hour average, 40 CFR 60 subpart D); 0.718 lb/MMBtu for blends of petroleum coke and any other fuels (30-day rolling average); and whenever coal or blends of coal and petroleum coke or refuse are burned, SO_2 gases discharged to the atmosphere from the boiler shall not exceed 10 percent of the potential combustion concentration (90 percent reduction), or 35 percent of the potential combustion concentration (65 percent reduction), when emissions are less than 0.75 lb/MMBtu heat input (30-day rolling average). For the most recent five-year period, more than 95 percent of the total heat content is due to bituminous coal firing.

Unit 6 is currently equipped with a wet limestone FGD system to control SO_2 emissions and is subject to New Source Performance Standard (NSPS) subpart D, which has no minimum SO_2 percent reduction requirements. However, the current title V permit requires a 65 percent reduction in SO_2 when the emissions are less than 0.75 lb/MMBtu (30-day rolling average) and a 90 percent reduction when emissions are greater than or equal to 0.75 lb/MMBtu (30-day rolling average). Based on the actual SO_2 emissions reported in 2002, the FGD system reduces SO_2 emissions by 81 percent.

Cost of Compliance: The source considered several changes and upgrades to the wet FGD system to further reduce SO_2 emissions, including lower sulfur fuel, wet FGD modifications, and complete replacement of the FGD system. Among the authorized fuels for Unit 6, petroleum coke has the highest sulfur content (average of 3.9 percent sulfur by weight), and bituminous coal (average of 1.8 percent sulfur by weight) is the fuel with next highest sulfur content. Lakeland Electric is authorized to burn up to 20 percent petroleum coke by weight with bituminous coal and, as a result, the average sulfur content of the combined fuel (coal and petroleum coke) can be as high as 2.2 percent (80 percent coal with 1.8 percent sulfur and 20 percent petroleum coke with 3.9 percent sulfur) due to the higher sulfur content of petroleum coke. Although coal is the most used fuel for Unit 6, petroleum coke can contribute significantly to the total SO_2 emissions from the unit, and Lakeland Electric believes that curtailing petroleum coke firing is the most cost-effective solution to reduce the sulfur content of fuel burned in Unit 6. The State estimated that 17 pounds of SO_2 would be reduced for every ton of coal burned when compared to the combined use of coal and petroleum coke (difference between 2.2 percent sulfur and 1.8 percent sulfur in one ton of fuel). Lakeland Electric did not provide costs for eliminating petroleum coke as an authorized fuel, and FDEP assumed that these costs would be minimal.

The existing FGD system is a 30-year old Babcock & Wilcox design that is not designed to achieve 95 to 98 percent SO_2 removal without significant major upgrades in the existing equipment. Based on a preliminary assessment, the removal efficiency of the FGD system could be increased to a maximum of 95 percent with equipment improvements to the existing wet FGD absorbers, slurry systems, additive systems, reheat systems, and other auxiliary equipment that are estimated to cost $25 million. Assuming that the existing wet FGD provides 81 percent control, an additional 14 percent control would reduce SO_2 emissions by another 5,153 tons based on 2002 SO_2 emissions from this unit of 6,994 tons. This would result in a cost-effectiveness of approximately $4,852 per ton of SO_2 reduction. FDEP does not consider this a reasonable cost-effectiveness value and therefore determined that upgrading the existing FGD system is not necessary for achieving the RPGs for this implementation period.

An additional/replacement wet FGD system designed to achieve 98 percent SO_2 removal would achieve the highest level of SO_2 control while Unit 6 remains operating and available to provide electric power to its customers. In estimating the cost of a replacement wet FGD system, FDEP used information developed for the Transport Rule. The annualized cost was based on the amount of historical operation in the baseline year of 2002 and is estimated to be approximately $36.3 million. FDEP estimated a cost-effectiveness of approximately $5,804 per ton of SO_2 removed using a target emissions rate of 0.063 lbs/MMBtu (equivalent to 98 percent SO_2 removal based on 2002 operations). FDEP did not consider this a reasonable cost-effectiveness value and therefore determined that an additional/replacement FGD is not necessary for achieving the RPGs for this implementation period.

Time Necessary for Compliance: The wet FGD system is already operating for this unit. The options for upgrading or replacing the existing wet FGD would each take a minimum of three years to complete whereas the option of reducing the potential fuel sulfur content could be completed immediately.

Energy and Non-Air Quality Environmental Impacts of Compliance: The energy and non-air quality environmental impacts associated with an additional/replacement wet FGD system include additional limestone usage, disposal of wet FGD byproducts, increased water use, and additional energy. FDEP estimated that wet FGD requires approximately three percent of the unit's energy output for auxiliary power and backpressure (approximately 1.09 MW per ton of SO_2 removed). For each ton of SO_2 removed, approximately 2.34 tons of wet FGD byproducts are produced, and for the estimated SO_2 removal increase based on 2002 emissions, an additional 6,572 tons of limestone would be required and 14,646 tons of byproducts generated. Approximately 312,953 gallons of additional process water would be required based on the SO_2 removal increase from 2002 emissions and an estimated water usage increase of approximately 50 gallons per ton of SO_2 removed.

Remaining Useful Life: These units are anticipated to operate indefinitely.

Conclusion: After considering the four reasonable progress factors for Lakeland Electric's McIntosh Unit 6, FDEP has determined that the existing wet FGD system at the current, permitted emissions limits with the elimination of petroleum coke as an authorized fuel meets the reasonable progress requirements for this implementation period.

5. JEA SJRPP

JEA's SJRPP Emissions Units 16 and 17 (commonly referred to as Boilers 1 and 2) are fossil fuel-fired EGUs rated at 679 MW each with a maximum heat input rate of 6,144 MMBtu/hr per boiler. The boilers are fired with pulverized coal, a coal blend with a maximum of 30 percent petroleum coke by weight, natural gas, new No. 2 distillate fuel oil (startup and low-load operation), and ''on specification'' used oil. The maximum coal or petroleum coke-coal blend sulfur content cannot exceed 4.0 percent by weight, and the maximum sulfur content of the No. 2 fuel oil is 0.76 percent by weight. Federally-enforceable permit conditions limit SO_2 emissions when burning coal to 1.2 lb/MMBtu on a maximum two-hour average and 0.76 lb/MMBtu on a 30-day rolling average (90 percent reduction of the potential combustion concentration).

Units 16 and 17 are equipped with wet FGD systems capable of up to 90 percent reduction in SO_2 emissions with a maximum SO_2 emissions rate of 0.76 lb/MMBtu (30-day average) using the worst-case fuel.

Cost of Compliance: The source considered several changes or upgrades to the wet FGD system to further reduce SO_2 emissions including lower sulfur fuel, wet FGD modifications, and complete replacement of the wet FGD system. Increasing the removal efficiency of the existing wet FGD system is possible with equipment improvements to the wet FGD absorbers, slurry systems, additive systems, reheat systems, and other auxiliary equipment. FDEP estimated the capital costs for the potential improvements to be in the range of $10 million to $30 million per boiler. In conjunction with the equipment improvements, operating costs for increased SO_2 removal would include fixed and variable operating costs from approximately $3 million per year per boiler to over $4.5 million per year per boiler. Depending upon the options selected, up to an additional five percent SO_2 removal is possible. An engineering study has commenced that will include an evaluation of the sulfur content for the various range of fuels authorized for SJRPP and a refinement of these very preliminary cost estimates. Since the unit is presently 90 percent controlled, FDEP has determined not to require these improvements for reasonable progress during this first implementation period.

Achieving greater SO_2 reductions than 90 percent would require either add-on SO_2 controls after the existing equipment or a replacement of the current wet FGD system with systems designed to achieve 95 to 98 percent or greater SO_2 removal. The existing wet FGD systems are not designed to achieve 95 to 98 percent SO_2 removal without significant major upgrades in the existing equipment. An additional/replacement FGD system designed to achieve a total removal of 98 percent SO_2 removal would be required to achieve the highest level of SO_2 control.

Units 16 and 17 are identically designed units in close proximity that have a similar influence on visibility in Class I areas. FDEP calculated an estimated annualized cost for an additional/replacement wet FGD system of $59.7 million based on an emissions rate of 0.053 lb/MMBtu, equivalent to 98 percent SO_2 removal, based on 2002 operations. FDEP estimated a cost-effectiveness of $6,383 per ton of SO_2 removed using a reduction from the 2002 baseline year and an emissions rate of 0.053 lb/MMBtu. Cost-effectiveness using the emissions from the latest full year, 2011, was also calculated to contrast the cost-effectiveness from the 2002 baseline year and was estimated at $11,921 per ton of SO_2 removed. FDEP does not consider these reasonable cost-effectiveness values for Units 16 and 17, and therefore determined that an additional/replacement wet FGD system is not necessary for meeting the reasonable progress requirements for this implementation period. Furthermore, it may not be possible to install add-on SO_2 equipment given spatial constraints at the site.

Time Necessary for Compliance: The existing wet FGD systems are already operating for these boilers. The option for replacing the existing FGD systems would take a minimum of three years to complete whereas the option of making improvements to the existing FGD systems, including reducing the potential fuel sulfur content, could be implemented in a shorter time frame.

Energy and Non-Air Quality Environmental Impacts of Compliance: The energy and non-air quality impacts associated with an additional/replacement wet FGD system include additional limestone usage, disposal of wet FGD byproducts, increased water usage, and additional energy. FDEP estimates that a wet FGD requires about three percent of the unit's energy output for auxiliary power and backpressure (approximately 1.09 megawatt-hour (MWh) per ton of SO_2 removed), requiring 10,189 MWh of additional energy to achieve 98 percent SO_2 removal from the 2002 baseline emissions. Based on 2002 emissions, an additional 9,815 tons of limestone would be required, 21,874 tons of byproducts would be generated, and approximately 467,389 gallons of additional process water would be required to achieve 98 percent removal.

Remaining Useful Life: These units are anticipated to operate for at least another 20 years.

Conclusion: After considering the four reasonable progress factors for JEA's SJRPP Emissions Units 16 and 17, FDEP has determined that the existing FGD control systems at the current, permitted emissions limits satisfy the reasonable progress requirement for the implementation period.

6. Enforceability

FDEP included the final determinations and, as appropriate, the permit modifications to address reasonable progress as Exhibit 2 of the September 17, 2012, amendment. FDEP added the required operational restrictions limiting emissions, along with the associated monitoring and recordkeeping provisions, to each affected facility's federally enforceable permits.

7. EPA Assessment

As noted in EPA's Reasonable Progress Guidance, states have wide latitude to determine appropriate control requirements for ensuring reasonable progress. States must consider the four statutory factors (identified in section III.A. of this action), at a minimum, in determining reasonable progress, but have flexibility in how to take these factors into consideration. EPA proposes to find that Florida fully evaluated all control technologies available at the time of its analysis and applicable to: GRU Deerhaven Unit 5; PEF—Crystal River Units 3 and 4; SECI Units 1 and 2; Lakeland Electric—C.D. McIntosh Boiler Unit 6; and JEA SJRPP Units 16 and 17. EPA also proposes to find that Florida consistently applied its criteria for reasonable compliance costs and appropriately and adequately considered the statutory factors in developing its reasonable progress determinations. Accordingly, EPA is proposing to approve the reasonable progress determinations for these eight units for the first implementation period.

B. BART Analyses

As discussed in section II and summarized in Table 2 of this action, the State's September 17, 2012, amendment identified 20 BART-eligible units at 11 facilities with EGUs that were subject to CAIR and found subject to BART that were included in the State's July 31, 2012, draft SIP amendment.[7] Under the *Guidelines for BART Determinations Under the Regional Haze Rule* contained in Appendix Y to 40 CFR Part 51 (BART Guidelines), a state may exempt sources from BART if they do not cause or contribute to visibility impairment in any Class I area. FDEP used a contribution threshold of 0.5 deciview to determine which sources were subject to BART in accordance with the BART Guidelines following a review by Florida that this threshold was appropriate for sources in the State. EPA proposed approval of the use of this contribution threshold in its May 25, 2012, proposed action on prior revisions to Florida's regional haze SIP and approved several BART determinations based on this threshold in its November 29, 2012, action (77 FR 71111).

Using a 0.5 deciview threshold, Florida determined that the City of Tallahassee Arvah B. Hopkins Unit 1 was not subject to BART. In addition, two of the remaining BART-eligible sources—Reliant Energy—Indian River Units 2 and 3 and PEF—Anclote Units 1 and 2—made changes to their operations in order to ensure that allowable emissions would not cause visibility impacts to exceed the 0.5 deciview threshold. All of these operational changes at Indian River Units 2 and 3 and Anclote Units 1 and 2 have been incorporated into their respective permits and are federally enforceable. EPA proposes to agree with Florida's findings that these five units are not subject to further BART review.

Florida determined that the remaining 15 BART-eligible units at eight facilities were subject to BART. In accordance with the BART Guidelines, to determine the level of control that represents BART for each source, the State first reviewed existing controls on these units to assess whether these constituted the best controls currently available, then identified what other technically feasible controls are available, and finally, evaluated the technically feasible controls using the five BART statutory factors (costs of compliance; energy and non-air quality environmental impacts of compliance; any existing emissions control technology in use at the source; the remaining useful life of the source; and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology). CAA section 169A(g)(2). The State's evaluations and conclusions are summarized below by facility, followed by EPA's assessment.

1. Gulf Power Crist

Gulf Power's Crist Electric Generating Plant is located in Escambia County, Florida, and consists of four active fossil fuel fired EGUs (Units 4, 5, 6, and 7), two of which are BART-eligible units (Units 6 and 7). The following Class I area is located within 300 km of the Gulf Power Crist facility: Breton National Wilderness Area (NWA)—250 km.[8] Pulverized coal is the primary fuel for Units 6 and 7, and natural gas, fuel oil, and on-specification used oil are used as supplemental fuels in all four of the units. The facility operates a wet FGD system to control SO_2 emissions from Units 4–7 by 95 percent; low NO_X burners (LNB) and SCR (designed to achieve no less than an 85 percent reduction) to control NO_X emissions from Units 6 and 7; and cold side ESPs to control PM emissions from Units 6 and 7. Federally enforceable title V permit emission limits for NO_X, SO_2, and PM are currently established. FDEP determined that existing controls at Units 6 and 7 represent the most stringent controls available, thus satisfying the BART requirements for SO_2, NO_X, and PM, as discussed below.

SO_2 BART: The facility utilizes a wet FGD system that began operating in 2009 to control SO_2 emissions from Units 4–7. These units share a common stack under normal conditions with the wet FGD system in operation. Since the wet FGD was installed on a common stack for Units 4–7, SO_2 emissions reductions occur from the control of the non-BART Units 4 and 5 as well as the BART Units 6 and 7. The system is designed to reduce SO_2 emissions by 95 percent and consists of a single scrubber reactor vessel and supporting subsystems for transporting and processing flue gas exhaust, limestone, gypsum or other solids, and water. FDEP determined that the wet FGD systems represent the most stringent controls available and the current, permitted emissions limits contained in FDEP's title V operating permit No. 0330045–031–AV are SO_2 BART for Units 6 and 7, and that no additional control measures are necessary.

NO_X BART: NO_X emissions from Units 6 and 7 are controlled by LNB and by SCRs designed to achieve no less than an 85 percent reduction in NO_X emissions. The SCR came on line in 2005 for Unit 7 and in 2012 for Unit 6. The current federally enforceable permit limits NO_X emissions from the combined operation of Units 4–7 to 0.2 lb/MMBtu heat input based on a 30-day rolling average except for periods when Unit 7 is shut down. FDEP determined that the technology applied at this facility is the top-level NO_X control for Units 6 and 7 and that the SCRs at the current, permitted emissions limits are NO_X BART for these EGUs.

PM BART: PM emissions from Units 6 and 7 are controlled by cold side ESPs

[7] On November 29, 2012, EPA finalized full approval of the BART determinations addressed in the April 13, 2012, draft regional haze SIP amendment.

[8] Florida adopted the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) modeling protocol that limits the CALPUFF modeling domain to a 300 km radius around the subject source. *See* 77 FR 31240.

with a federally enforceable PM emissions limit of 0.1 lb/MMBtu heat input. FDEP determined that the technology applied at this facility is the top-level PM control and that the current, permitted emissions limits for Units 6 and 7 are PM BART for these EGUs.

Summary of FDEP's BART Determination for Gulf Power Crist: FDEP determined that the current, permitted emissions limits satisfy BART for SO_2, NO_X, and PM. No new limits or changes to existing limits were adopted for BART. The existing operating conditions for units 4–7 are incorporated in the FDEP title V operating permit No. 0330045–031–AV.

2. FPL Martin

The Martin Power Plant is located in Martin County, Florida. The following Class I areas are located within 300 km of the Martin Plant: Chassahowitzka NWA–145 km and Everglades National Park (NP)–267 km. The facility consists of two oil and natural gas-fired conventional fossil fuel steam EGUs (Units 1 and 2), two oil and natural gas-fired combined cycle units (Units 3 and 4), four oil and natural gas-fired combined-cycle combustion turbines (Unit 8), and associated support equipment. Only Units 1 and 2 are subject to BART. Units 1 and 2 each have a maximum capacity of 863 MW and are equipped with LNB to reduce NO_X emissions and multi-cyclones with fly ash reinjection to control PM emissions. Separate from the BART determination, FPL is currently planning to install ESPs for the purpose of controlling PM emissions from Units 1 and 2. The projected ESP installation date is first quarter of 2014 for Unit 1 and the fourth quarter of 2014 for Unit 2. The ESPs are expected to reduce PM emissions compared to the currently permitted rates. FDEP has determined that existing controls at the current, permitted emissions limits for the affected pollutants SO_2, NO_X, and PM are BART for the Martin Plant, as discussed below.

SO_2 BART: The options evaluated for SO_2 control included use of low sulfur fuel (0.3 percent and 0.7 percent) and FGD. These units are currently subject to the NSPS subpart Da limit of 0.8 lb/MMBtu when firing fuel oil. This plant fires blends of natural gas and/or fuel oil as needed to comply with this SO_2 limit. FDEP determined that the current operating practice of using 0.7 percent sulfur fuel oil burned alone, or co-fired with the requisite amount of natural gas, in order to comply with the NSPS limit of 0.8 lb/MMBtu, is SO_2 BART for Units 1 and 2.

FGD: The BART analysis submitted by FPL discussed various post-combustion control technologies that rely on chemical reactions within the control device to reduce the concentration of SO_2 in the flue gas. These included wet FGD and dry FGD. FDEP determined that wet and dry FGD systems, typically used for coal-fired boilers, are not a technically viable option for oil/gas-fired utility boilers such as Units 1 and 2.

Lower sulfur oil: CALPUFF air quality modeling indicates that the baseline 98th percentile visibility impact using the current permit limit of 0.8 lb/MMBtu (assured by firing fuel oil containing 0.7 percent sulfur) is 2.3 deciviews at the nearest Class I area (Chassahowitzka NWA) and that the total modeled 98th percentile visibility improvement using 0.3 percent sulfur fuel would be 1.07 deciviews, for a modeled improvement of 1.23 deciviews.[9] The resulting average visibility improvement cost-effectiveness is approximately $155 million per deciview. In addition to the BART analysis submitted by FPL, FDEP calculated that the cost-effectiveness of reducing the sulfur content of the fuel oil from 0.7 percent to 0.3 percent is approximately $7,348 per ton based on FPL-supplied data on fuel prices, energy content, and density. FDEP therefore concluded that switching to 0.3 percent sulfur fuel is not SO_2 BART as it is not cost-effective.

NO_X BART: Units 1 and 2 are currently equipped with flue gas recirculation (FGR), overfire air systems, staged combustion, and LNB. SCR was the only available additional control option identified in FPL's BART analysis. FDEP concluded that SCR is not cost-effective for Units 1 and 2 and that the existing NO_X reduction practices in use (FGR, overfire air systems, staged combustion, LNB, and good combustion practices) are NO_X BART for Units 1 and 2 for the reasons discussed below.

SCR: FPL performed a BART cost-effectiveness calculation using a control efficiency of 90 percent and direct and indirect capital costs and operation and maintenance costs for SCR from a study conducted in 2006 for Martin Units 1 and 2. FPL concluded that SCR would require a direct capital investment of approximately $100 million per unit with a cost-effectiveness of $5,323 per ton based on direct and indirect capital costs as well as operation and maintenance costs totaling approximately $31 million. CALPUFF modeling results indicate that only six to seven percent of the total visibility impact at the nearest Class I area is attributable to the NO_X emissions from these units and that the visibility improvement from SCR would be approximately 0.15 deciview, resulting in a visibility cost-effectiveness of approximately $203 million per deciview.

PM BART: FPL evaluated ESPs as possible PM BART for Units 1 and 2. ESPs are common particulate controls on utility boilers with a control effectiveness of 99 percent. FPL concluded that control of PM emissions from Units 1 and 2 will not provide a meaningful reduction in visibility impacts. FDEP concluded that the addition of ESPs to these units is not cost-effective and therefore not PM BART for these units as discussed below. However, FPL plans to install ESPs on Units 1 and 2 in 2014 for the purpose of controlling PM.

ESP: The capital cost for ESP on each BART-subject unit is approximately $55.6 million. Records of actual reported annual emissions reveal that PM emissions in 2010 were 311 tons from Unit 1 and 247 tons from Unit 2. Assuming an ESP control efficiency of 98 percent, these emissions could be reduced by a total of 547 tons annually. Cost-effectiveness is therefore $9,595 per ton based on estimated annualized capital costs of approximately $5.3 million per year and assuming no additional maintenance and operating costs. CALPUFF baseline visibility modeling showed that only four to six percent of the total visibility degradation at the nearest Class I area attributable to Units 1 and 2 at Martin is due to PM emissions, translating into less than a 0.1 deciview impact at any Class I area. FPL therefore concluded that control of PM emissions from Units 1 and 2 will not provide a meaningful reduction in visibility impacts. FDEP concluded that the addition of ESPs to these units is not cost-effective and therefore not PM BART.

Summary of FDEP's BART Determination for the Martin Plant: FDEP determined that existing controls already in place at the current, permitted emissions limits for the affected pollutants SO_2, NO_X, and PM are BART for the Martin Plant. Units 1 and 2 meet BART requirements by continuing to comply with the existing operational and emissions limiting standards for each pollutant as summarized below.

[9] EPA assessed whether the visibility impacts of FPL Martin on other nearby Class I areas would affect any of FDEP's BART determinations for this facility. The FPL Martin Plant has comparable but lesser impacts on a second Class I area (Everglades NP), and EPA concluded that consideration of these impacts would not change the determinations.

SO_2: 0.80 lb/MMBtu when firing liquid fossil fuel, met by firing natural gas, co-firing natural gas with fuel oil containing less than one percent sulfur, or firing fuel oil alone containing less than 0.7 percent sulfur.

NO_X: 0.2 lb/MMBtu when firing natural gas, 0.3 lb/MMBtu when firing fuel oil, pro-rated based on heat input when co-firing gas and oil. The limits are met through the use of FGR, overfire air systems, staged combustion, and LNB.

PM: 0.1 lb/MMBtu when firing fuel oil. The limit is met by firing natural gas, co-firing natural gas with fuel oil containing less than one percent sulfur, or firing fuel oil alone containing less than 0.7 percent sulfur, and through the use of multi-cyclones (mechanical dust collectors) and fly ash reinjection.

3. FPL Manatee

FPL's Manatee Plant is located in Manatee County, Florida. The following Class I areas are located within 300 km of the Manatee Plant: Chassahowitzka NWA–116 km and Everglades NP–212 km. This facility consists of two oil and natural gas-fired 800 MW (900 MW gross capacity) conventional steam EGUs (Units 1 and 2), a ''4 on 1'' gas-fired combined cycle unit (Unit 3A–3D), and miscellaneous insignificant emissions units. Only Units 1 and 2 are BART-eligible. Each of these two units is equipped with ESPs for PM and a FGR system along with reburn and staged combustion for NO_X. In addition, FPL recently submitted a permit application to FDEP seeking an increase in the natural gas capacity of these units from 5,670 MMBtu/hr to 8,650 MMBtu/hr to displace the use of more residual fuel oil which will raise the allowable natural gas capacity in the permit to equal the oil-firing permit capacity. The proposed increased utilization of natural gas is also expected to reduce SO_2, PM, and NO_X emissions from Units 1 and 2. In addition, FDEP has determined that SO_2 emissions and visibility impacts can be reduced by switching to low sulfur fuel oil containing a maximum of 0.7 percent sulfur content or to a mixture of low sulfur fuel oil containing a maximum of 1.0 percent sulfur and natural gas in a ratio not to exceed the SO_2 emissions limit of 0.80 lb/MMBtu heat input. FDEP has also determined that the controls already in place, or soon to be in place, at the current, permitted emissions limits for NO_X and PM are BART for Units 1 and 2, as discussed below.

SO_2 BART: FPL evaluated the use of low sulfur fuel (0.3 percent and 0.7 percent sulfur content) and FGD, for controlling SO_2 emissions from Units 1 and 2. These units currently burn natural gas, distillate, or residual fuel oil and are subject to the NSPS subpart D limit of 0.80 lb/MMBtu when firing fuel oil. The facility's title V permit limits the sulfur content of fuel oils burned to a maximum of 1.0 percent by weight, as received at the facility, and the blending of natural gas is not allowed to demonstrate compliance with the SO_2 limit. FDEP determined that the switch from the current 1.0 percent sulfur fuel to 0.7 percent sulfur fuel oil burned alone, or co-fired with the requisite amount of natural gas, in order to comply with the NSPS limit of 0.80 lb/MMBtu, is SO_2 BART for Units 1 and 2, as discussed below.

FGD: The BART analysis submitted by FPL discussed various post-combustion control technologies that rely on chemical reactions within the control device to reduce the concentration of SO_2 in the flue gas. These included a wet FGD and dry FGD. FPL provided generic cost information but cautioned that it was for illustrative purposes and that detailed wet FGD cost estimates had not been developed. These generic cost estimates are believed to underestimate the true cost because they do not consider additional retrofit costs that would be expected for adding FGD systems on Units 1 and 2 at Manatee. In addition, FPL believes that it may not technically feasible to construct wet FGD without major demolition efforts that would affect the continued operation of these units. FDEP agrees with FPL that wet or dry FGD systems are typically used for coal-fired boilers and not for oil/gas-fired boilers. This fact, coupled with high capital costs (ranging between $40 and $100 million), led FDEP to the conclusion that FGD would be cost prohibitive. FDEP therefore reject this option in the BART analysis.

Low Sulfur Fuel: The refined oil products that are readily available to FPL's Manatee Plant include 0.3 percent and 0.7 percent sulfur grades. The total annual cost of switching Units 1 and 2 from the fuel currently used to 0.7 percent or 0.3 percent sulfur fuel oil would exceed $85 million and $240 million, respectively. However, switching from 1.0 percent to 0.7 percent or 0.3 percent sulfur fuel oil is a strategy to lower emissions of SO_2 with no added capital investment. FDEP calculated the cost-effectiveness of switching to 0.7 percent and 0.3 percent sulfur fuel oil from the current baseline of 1.0 percent oil to be $5,468/ton and $6,542/ton, respectively, based on the information provided by FPL with an estimated cost-effectiveness of $7,348/ton in lowering the sulfur level in the fuel oil from 0.7 percent to 0.3 percent.

CALPUFF air quality modeling indicates that the baseline visibility impact using the current permit limit (firing fuel oil containing 1.0 percent sulfur) from Units 1 and 2 at Manatee is 4.07 deciviews at the nearest Class I area (Chassahowitzka NWA) and that the total improvement in visibility using 0.7 percent and 0.3 percent sulfur fuel would be 0.87 deciview and 2.38 deciviews, respectively.[10] The resulting average visibility improvement cost-effectiveness is calculated at approximately $100 million per deciview burning 0.7 percent sulfur fuel and $102 million per deciview burning 0.3 percent sulfur fuel. Because the overall costs of improvement are high for switching to the 0.3 and 0.7 percent sulfur fuels, FDEP concluded that these options are not cost-effective. However, FDEP determined that equivalent visibility improvements to those that could be achieved by switching to 0.7 percent fuel oil could be achieved by removing the current prohibition on blending and co-firing 1.0 percent oil with natural gas and by lowering the allowable emissions limit to 0.8 lb/MMBtu (12-month rolling average), consistent with the NSPS for this source category. FDEP has determined that these changes constitute BART for SO_2 for Units 1 and 2.

NO_X BART: Units 1 and 2 are currently equipped with FGR, overfire air systems, staged combustion, LNB, and reburn. SCR was the only available additional control option identified in FPL's analysis. FPL calculated cost-effectiveness using direct and indirect capital costs and the operation and maintenance costs for SCR from a study conducted in 2006 for Units 1 and 2 and a control efficiency of 90 percent (reducing NO_X emissions by 8,229 tons per year). FPL calculated that the annualized cost to purchase and operate SCR on both units would be approximately $31 million with a cost-effectiveness of $3,776/ton of NO_X reduced. Based on the CALPUFF modeling results, NO_X emissions from Units 1 and 2 contribute only six to 17 percent of the total visibility impact on the nearest Class I area. The resulting visibility cost-effectiveness is approximately $66 million per deciview using a capital expenditure of approximately $100 million per unit

[10] EPA assessed whether the visibility impacts of FPL Manatee on other nearby Class I areas would affect any of FDEP's BART determinations for this facility. The FPL Manatee Plant has comparable but lesser impacts on a second Class I area (Everglades NP), and EPA concluded that consideration of these impacts would not change the determinations.

and annual operating costs of approximately $6 million. FDEP concluded that SCR was not cost-effective for Units 1 and 2 and that the existing controls of LNB, reburn, overfire air system, staged combustion, and FGR, along with good combustion practices, at the current, permitted emissions limits is NO_X BART for Units 1 and 2.

PM BART: FDEP has issued federally enforceable permits limiting PM emissions to 0.03 lb/MMBtu through the replacement of the existing cyclones with ESPs. The in-service dates for the ESPs for Units 1 and 2 are the third quarter of 2012 and fourth quarter of 2013, respectively. FDEP determined that ESPs are the most stringent controls available for PM emissions from these EGUs, and therefore constitute PM BART. As a result, FDEP did not consider additional retrofit technologies for PM BART.

Summary of FDEP's BART Determination for FPL's Manatee Plant: FDEP has determined that existing controls achieving the current, permitted emissions limits for NO_X and new ESPs soon to be in place for PM are BART for Units 1 and 2. FDEP has also determined that switching to a lower sulfur fuel oil as specified in the permit for Manatee is SO_2 BART. The following operational and emissions limits are BART for Units 1 and 2:

SO_2: Authorized fuels to be burned are low sulfur fuel oil containing a maximum of 0.7 percent sulfur content, by weight; natural gas; or a mixture of low sulfur fuel oil containing a maximum of 1.0 percent sulfur content (by weight) and natural gas in a ratio that shall not exceed the SO_2 emissions limit of 0.80 lb/MMBtu heat input (12-month rolling average).

NO_X: Emissions shall not exceed 0.3 lb/MMBtu as demonstrated by continuous emissions monitoring systems (CEMS). The limit is met through the use of FGR, overfire air systems, reburn, staged combustion, and LNB.

PM: Emissions shall not exceed 0.03 lb/MMBtu during normal operation. Compliance is demonstrated by stack testing.

4. Lakeland Electric C.D. McIntosh

The Lakeland Electric C.D. McIntosh Jr. Power Plant is located in Polk County, Florida, and has two BART-subject units. Unit 1 is a pre-NSPS boiler with a nominal rating of 985 MMBtu/hr fired by natural gas and fuel oil and no emissions controls. Emissions Unit 5 (commonly referred to as Unit 2 or Boiler 2) is a NSPS subpart D boiler with a nominal rating of 1,185 MMBtu/hr heat input equipped with FGR for NO_X control and no add-on PM or SO_2 controls.

The following Class I areas are located within 300 km of the C.D. McIntosh facility: Chassahowitzka NWA–91 km, Everglades NP–249 km, and Okefenokee NWA–277 kilometers. The visibility impact analysis was performed only for the Chassahowitzka NWA, the nearest Class I area and the only Class I area where the visibility impacts from this facility are predicted to be higher than 0.5 deciview.[11]

FDEP has determined that the use of 0.7 percent sulfur fuel oil and existing controls achieving the current, permitted emissions limits for the affected pollutants SO_2, NO_X, and PM are BART for Units 1 and 2, as discussed below.

SO_2 BART: FDEP evaluated the use of low sulfur fuel and FGD, as possible SO_2 controls. Unit 2 is currently limited to 0.7 percent fuel oil, and FDEP considered the option of utilizing this low sulfur fuel oil in Unit 1. Unit 1 is subject to Florida Rule 62–296.405(1)(c)1.a that limits SO_2 emissions to 2.75 lb/MMBtu when firing fuel oil. FDEP expects that the Utility MATS rule will result in this facility being operated as an oil-fired EGU subject to the provisions for limited-use liquid oil-fired facilities and that it will limit the unit's liquid fuel oil utilization to less than eight percent of its maximum or nameplate heat input starting in 2015. Lakeland Electric C.D. McIntosh has agreed to utilize the 0.7 percent low sulfur fuel oil in Unit 1, consistent with the fuel used in Unit 2. FDEP has determined that new shipments of fuel oil for Unit 1 will be limited to 0.7 percent sulfur content, the same as in Unit 2, and that this low sulfur fuel oil control option is SO_2 BART for these units for the reasons discussed below. A federally enforceable permit condition assures this operating condition.

FGD: The BART analysis submitted by FPL discussed various post-combustion control technologies that rely on chemical reactions within the control device to reduce the concentration of SO_2 in the flue gas. These included wet FGD and dry FGD. These control alternatives allow the use of high sulfur fuel oil with an assumed 98 percent removal efficiency for the maximum annual SO_2 emissions for Units 1 and 2 over the period 2001 through 2003. FDEP calculated an annualized cost of $36.2 million with an average cost-effectiveness of approximately $13,200 per ton of SO_2 removed for wet FGD on both Units 1 and 2. These estimated costs are not specific to the C.D. McIntosh Plant nor the layout of Units 1 and 2, and are believed to underestimate the true cost as they do not consider any site-specific additional retrofit costs. FPL believes that it may not be possible to install add-on SO_2 controls given the space constraints at the facility. For these reasons, FDEP concluded that FGD is not considered appropriate technology for oil/gas-fired boilers like C.D. McIntosh Units 1 and 2, and therefore rejected this option in the BART analysis.

Low Sulfur Fuel: Unit 1 currently burns natural gas and fuel oil and Unit 2 burns only fuel oil. The facility's federally enforceable title V permit limits the sulfur content of the fuel oil to a maximum of 2.5 percent for Unit 1 and 0.7 percent for Unit 2. FPL evaluated the use of 0.7 percent sulfur grade fuel oil in Unit 1, a control method that can result in lower emissions of SO_2 with no added capital investment and reduce emissions by more than 50 percent compared to the currently fired high sulfur fuel oil. FDEP determined that the resulting cost-effectiveness is $2,231/ton. CALPUFF air quality modeling indicates that the baseline 98th percentile visibility impact at the nearest Class I area (Chassahowitzka NWA) using the current permit limit of 2.75 lb/MMBtu for Unit 1 (based on firing fuel oil containing 2.5 percent sulfur) and Unit 2 (0.7 percent sulfur fuel oil) is 1.62 deciviews and that the total modeled 98th percentile visibility improvement using 0.7 percent sulfur fuel for Unit 1 would be 0.74 deciview.

NO_X BART: Unit 1 has no NO_X emissions controls other than best operating practices for good combustion. As mentioned previously, Unit 2 has FGR controls for NO_X and currently meets a federally enforceable NO_X permit limit of 0.2 lb/MMBtu with compliance demonstrated by CEMS. Lakeland Electric evaluated SCR as possible control for Units 1 and 2. FDEP concluded that NO_X BART is the current limit of 0.2 lb/MMBtu for Unit 2 and no add-on NO_X control for Unit 1.

SCR: FDEP estimates that a control efficiency of 80 percent can be achieved by SCR, on average, for these units. FDEP assumed that SCR is the top-level add-on NO_X control technology for Units 1 and 2 and calculated an annualized cost of $2.7 million with a cost-effectiveness of $5,241 per ton of

[11] EPA assessed whether the visibility impacts of C.D. McIntosh on other nearby Class I areas would affect any of FDEP's BART determinations for this facility and concluded that consideration of these impacts would not change the determinations.

NO_X. The operation of SCR would result in a power requirement of approximately 0.6 percent (2,800 MWh per year) of each unit's power output due to the backpressure of the SCR catalyst and auxiliaries, and there would be some non-air quality environmental impacts associated with the storage and handling of ammonia. Based on CALPUFF modeling results, approximately 19 percent of the total visibility impact on the nearest Class I area is attributable to the NO_X emissions from Units 1 and 2. FDEP's analysis indicated that SCR would result in a visibility improvement of 0.25 deciview at Chassahowitzka NWA. For these reasons, FDEP concluded that SCR is not cost-effective as NO_X BART for these units.

PM BART: Units 1 and 2 are not equipped with PM controls. The existing PM emissions limits for Unit 1are 0.1 lb/MMBtu for normal operation and 0.3 lb/MMBtu for soot-blowing operation. Unit 2 has a limit of 0.1 lb/MMBtu at all times. Lakeland Electric evaluated add-on PM controls including fabric filters, ESPs, and wet FGDs to control PM emissions and identified fabric filters and wet FGDs as technically infeasible options. Based on the costs and the limited use of fuel oil for Unit 1 and 2, FDEP concluded that the addition of an ESP is not cost-effective as PM BART for these units, as discussed below.

Baghouse or venturi scrubber: The feasibility of a fabric filter baghouse depends on site-specific exhaust characteristics such as particulate loading, temperature, and moisture content. The use of a fabric filter control device is uncommon for large oil-fired boilers like Units 1 and 2. The proposed BART analysis in the SIP indicates that PM from firing fuel oil can be sticky which can cause problems with cleaning fabric filters and interfere with effective operation. Likewise, venturi scrubbers are not commonly used for large oil-fired units. In this case, FDEP also determined that venturi scrubbers are undesirable for these units due to the non-air quality environmental impacts associated with wastewater disposal. For these reasons, FDEP concluded that the options of a baghouse or venturi scrubber are not viable as PM BART for these units.

ESP: FDEP determined that an ESP is the only feasible PM BART control option for Units 1 and 2 and that an ESP is the most common and technically feasible option for these types of units. FDEP also concluded that ESPs have a control efficiency of greater than 99 percent and that other technologies have not demonstrated equivalent levels of control for PM compared to an ESP in this application.

FDEP calculated capital and annualized costs for an ESP for both units of approximately $3 million with a cost-effectiveness of $65,865 per ton of PM removed. In addition, FDEP concluded that the installation of ESP would result in a power usage of approximately 0.3 percent (1,400 MWh per year) of each unit's power output due to electric field current usage and backpressure; there would be some non-air quality environmental impacts associated with the disposal of ash in a Class I landfill; and that the installation of an ESP would require approximately two years for construction based on experience from recent retrofit projects. CALPUFF modeling indicates that PM only contributes approximately five percent of the total visibility impact (approximately 0.07 deciview) from Units 1 and 2 at the nearest Class I area. FDEP calculated visibility cost-effectiveness for an ESP at more than $41.7 million per deciview based on the annual costs and estimated visibility improvement identified above.

Summary of FDEP's BART Determination for Lakeland Electric C.D. McIntosh: As discussed above, FDEP has determined that the continued use of 0.7 percent sulfur fuel oil at Unit 2 and the switch to 0.7 percent sulfur fuel oil at Unit 1 as specified in the permit for Lakeland Electric McIntosh constitutes BART for SO_2, and that the controls already in place at the current, permitted emissions limits for NO_X and PM are BART for those pollutants. As identified below, Units 1 and 2 meet BART requirements by complying with the existing NO_X and PM operational and emissions limiting standards at both units, the existing SO_2 standards for Unit 2, and a new SO_2 standard for Unit 1.

SO_2: 0.80 lb/MMBtu when firing fuel oil, met by any of the following options: firing natural gas, co-firing natural gas with fuel oil, or firing fuel oil alone containing not more than 0.7 percent sulfur. Compliance is demonstrated by CEMS.

NO_X: 0.20 lb/MMBtu when firing natural gas or firing fuel oil for Unit 2 by use of the existing FGR controls. Compliance is demonstrated by CEMS. Unit 1 is uncontrolled for NO_X.

PM: 0.1 lb/MMBtu when firing fuel oil and 0.3 lb/MMBtu for soot blowing for Unit 1 and 0.1 lb/MMBtu for Unit 2 at all times. These limits can be met by any of the following options: firing natural gas, co-firing natural gas with fuel oil, or firing fuel oil alone containing less than 0.7 percent sulfur.

5. JEA Northside

JEA's Northside Generating Station is located in Duval County, Florida. The following Class I areas are located within 300 km of the JEA Northside facility: Okefenokee NWA–63 km, Wolf Island NWA–100 km, Chassahowitzka NWA–217 km, and Saint Marks NWA–240 km. Unit 3, the only BART-eligible unit at Northside, is a pre-NSPS boiler with a nominal rating of 564 MW that is fired by natural gas, landfill gas, residual fuel oil, and used oil and is equipped with LNB. Units 1 and 2 are repowered units that were converted to circulating fluidized bed boilers firing mainly petroleum coke and coal (about 10 percent) fuel blends. As part of the repowering of Units 1 and 2, JEA made a commitment to reduce SO_2, NO_X, and PM emissions to 10 percent below the 1994 and 1995 baseline years used in the permitting of the repowering project. As a result, emissions caps for each of these pollutants were incorporated into the federally enforceable permit. Because the repowered units are more efficient and better controlled, operation of Unit 3 was reduced when the new repowered units became operational.

Based on the operation of Unit 3 on oil, the emissions cap that most limits operation is the NO_X cap, which is limited by a federally enforceable title V permit to 3,600 tons per year for Units 1, 2, and 3 over a 12-month rolling average. Based on the sulfur content of the fuels used in Unit 3 in 2002, this annual NO_X limit restricts SO_2 emissions from oil firing to about 9,000 tons per year if Units 1 and 2 are not operating, equivalent to a capacity factor of about 21 percent at the authorized emissions rate. If Units 1 and 2 are fully operational (the usual case), Unit 3 is limited to a maximum of 3,506 tons of SO_2 per year, equivalent to a capacity factor of approximately eight percent at the authorized emissions rate. FDEP has determined that the limited use of fuel oil and the controls already in place at the current, permitted emissions limits are BART for Unit 3. These conditions are included in a federally-enforceable title V permit (No. 0310045–030–AV as condition G.11.b.).

SO_2 BART: Unit 3 is subject to Florida Rule 62–296.405(1)(c)1.a that limits emissions to 1.98 lb of SO_2/MMBtu when firing fuel oil. FDEP identified the use of low sulfur fuel (1.0 percent sulfur grade fuel oil) and FGD, as potential SO_2 control for this unit. FDEP determined that the current operating practice of using no more than 1.8 percent sulfur fuel oil burned alone, or higher sulfur fuel oil co-fired with the requisite amount of natural gas, in order to

comply with the 1.98 lb/MMBtu emissions limit discussed above, is SO_2 BART for Unit 3.

FGD: JEA's BART analysis discussed various post-combustion control technologies that rely on chemical reactions within the control device to reduce the concentration of SO_2 in the flue gas. These included wet and dry FGD . The analysis states that post-combustion controls are typically applied to coal-fired boilers and not to oil-fired units due to chemical reaction technology considerations and efficiencies, and FDEP agrees that add-on controls such as FGD are not a feasible option for Unit 3 which has a limited capacity factor (effectively eight percent) for fuel oil. JEA listed the comparable best available control technology (BACT) determinations for SO_2 controls on oil and gas-fired boilers and stated that none of the comparable oil and gas-fired boilers employed add-on sulfur controls for BACT, but rather utilized low sulfur fuel oil as a means of reducing emissions. According to JEA, it may not be technically feasible to construct wet and dry FGD at Northside without major demolition efforts that would affect the continued operation of this unit.

Lower Sulfur Oil: Switching from 1.8 percent sulfur fuel oil to 1.0 percent sulfur fuel oil is a control method that can result in lower emissions of SO_2 with no added capital investment. FDEP calculated that the cost-effectiveness of converting to 1.0 percent fuel oil from 1.8 percent fuel oil would be $7,184/ton. CALPUFF air quality modeling indicates that the baseline visibility impact using the current permit limit of 1.98 lb/MMBtu (assured by firing fuel oil containing 1.8 percent sulfur) is 3.61 deciviews at the nearest Class I area (Okefenokee NWA) and that the total visibility improvement using one percent sulfur fuel would be 1.08 deciviews. FDEP calculated a resulting average visibility improvement cost-effectiveness of $31.1 million per deciview.

NO_X BART: Unit 3 is currently equipped with LNB, and JEA evaluated SCR and Selective Non-Catalytic Reduction (SNCR) as possible control methods. JEA conducted a feasibility study on this unit and found that the temperature window for the conversion reaction of SNCR was not available on Unit 3, and therefore, that SNCR is not feasible. For its SCR evaluation, FDEP estimated a NO_X control effectiveness of 80 percent corresponding to an emissions reduction of approximately 1,137 tons annually from Unit 3. This value is based on the base load operation of Units 1 and 2 since the three units are subject to a total emissions cap of 3,600 tons per year of NO_X. JEA estimated the capital and annualized costs of SCR to be $30 million and $5.2 million, respectively, with a cost-effectiveness in excess of $4,500/ton. CALPUFF modeling indicates that SCR on Unit 3 would improve visibility by approximately 0.26 deciview at the Okefenokee NWA, resulting in a visibility cost-effectiveness exceeding $20 million per deciview. The analysis adjusted the visibility evaluation to account for the impact of the NO_X cap on the number of days the unit can operate. For the reasons discussed above, FDEP concluded that existing controls are NO_X BART for Unit 3.

PM BART: JEA evaluated add-on controls including fabric filters (e.g., baghouses), ESPs, and venturi scrubbers to control PM emissions and determined that fabric filters and PM scrubbers are technically infeasible for Unit 3. JEA stated that fabric filters are not common for large oil-fired boilers like Unit 3 and that the PM from firing fuel oil can be sticky which can cause problems with cleaning fabric filters and adversely affect control efficiency. Likewise, JEA stated that wet PM scrubbers like venturi scrubbers are not commonly used for large oil-fired units such as Unit 3 and that it would not further consider these controls as BART because of lower control efficiencies (60–90 percent), relatively high operating and maintenance costs, and wastewater disposal issues. Although FDEP considers ESP to be the most common and technically feasible option for Unit 3, it determined that no PM control was appropriate for BART for the reasons discussed below.

ESP: JEA estimated the total capital cost of an ESP at approximately $60 million with a potential reduction in PM emissions of approximately 449 tons per year and an estimated annualized cost of approximately $8.1 million. Using this estimated annualized cost, JEA calculated a cost-effectiveness of $18,083 per ton of PM removed; however, considering the limited use of fuel oil under the federally enforceable limit/cap on emissions, JEA calculated a cost-effectiveness of approximately $29,000 per ton of PM removed. CALPUFF modeling indicates that PM emissions from Unit 3 account for a 0.18 deciview impact at the nearest Class I area (five percent of the maximum 8th highest 24-hour average visibility impact) and that the estimated improvement from the installation of an ESP is 0.10 deciview. Using this estimated visibility improvement and the annualized cost of $8.1 million, the resulting visibility cost-effectiveness is more than $78 million per deciview. JEA also evaluated the other statutory BART factors, including operating costs and remaining useful life, and determined that the installation of ESP will result in a power usage of approximately 0.3 percent (3,600 MWh per year) due to electric field current usage and backpressure and that there would be some non-air quality environmental impacts associated with the disposal of 63 to 148 tons of fly ash annually at a Class I landfill.

Summary of FDEP's BART Determination for JEA Northside: FDEP has determined that the limited use of fuel oil and the controls already in place at the current, permitted emissions limits are BART for Unit 3 at the JEA Northside Plant. This unit will meet the BART requirements by continuing to comply with the following operational and emissions limiting standards:

SO_2: 1.98 lb/MMBtu when firing fuel oil, met by firing natural gas, co-firing natural gas with fuel oil, or firing fuel oil alone containing not more than 1.8 percent sulfur.

NO_X: 0.30 lb/MMBtu when firing natural gas or firing fuel oil. Limits are met through the use of best operating practices for good combustion. Compliance is demonstrated by CEMS.

PM: 0.1 lb/MMBtu when firing fuel oil and 0.3 lb/MMBtu for soot blowing. These limits are met by firing natural gas, co-firing natural gas with fuel oil, or firing fuel oil alone containing less than 1.8 percent sulfur.

6. Gulf Power Lansing Smith

Gulf Power's Lansing Smith Plant is located in Bay County, Florida. The following Class I area is located within 300 km of the Lansing Smith Plant: Saint Marks NWA–149 km. The facility consists of two coal-fired EGUs (Units 1 and 2), two simple cycle peaking units, two combined cycle combustion turbines, and miscellaneous insignificant emissions units. Units 1 and 2 are subject to BART and burn coal, distillate fuel oil, or on-specification used fuel oil. Distillate fuel oil is only used during start-up and flame stabilization, and combustion of on-specification used oil is limited to no more than 50,000 gallons per calendar year per boiler. Unit 1 has a maximum authorized heat input rate of 1,944.8 MMBtu/hr and Unit 2 has a maximum authorized heat input rate of 2,246.2 MMBtu/hr. Units 1 and 2 are both are equipped with hot and cold side ESPs and SNCR. Unit 1 is also equipped with LNB with high momentum injection ports, and Unit 2 has LNB with an overfire air control system.

FDEP has determined that the controls already in place at the current, permitted emissions limits for NO_X and PM are BART for Units 1 and 2. FDEP has also determined that SO_2 emissions and visibility impacts can be further reduced by switching Units 1 and 2 to lower sulfur coal and installing dry sorbent injection (DSI) using trona as a reagent and that these control measures are BART for SO_2 as discussed below. The use of wet FGD, instead of DSI plus low-sulfur coal option, results in an incremental improvement in visibility of only 0.19 deciview for Unit 1 and 0.22 deciview for Unit 2 for the maximum 8th highest day and 0.07 deciview for Unit 1 and 0.09 deciview for Unit 2 for the 22nd highest day over three years at Saint Marks NWA (the nearest Class I area to the facility).[12]

SO_2 BART: FDEP evaluated the following options for SO_2 control: (1) Switch to lower sulfur coal, (2) DSI with use of lower sulfur coal, (3) dry FGD lime spray dryer absorber (SDA), and (4) wet FGD. All of these SO_2 control technologies are considered technically feasible for Units 1 and 2. FDEP's SO_2 BART determination for Units 1 and 2 is a SO_2 emissions rate of 0.74 lb/MMBtu on a 30-day rolling average which can be achieved with the use of DSI with trona as the alkaline reagent. FDEP concluded that FGD is not cost-effective when considering the estimated costs and associated visibility improvement, as discussed below.

Low Sulfur Coal: Gulf Power states that the use of lower sulfur Columbian coal can result in lower SO_2 with no added capital investment and that switching Units 1 and 2 to lower sulfur coal would reduce SO_2 emissions by approximately 25 percent. The fuel switch to lower sulfur coal was assumed to have no additional costs; therefore, Gulf Power did not conduct any further economic analyses for this control option.

DSI with Low Sulfur Coal: DSI is a dry technology that uses an alkaline reagent to absorb SO_2. DSI control technology injects reagent (e.g., trona) directly into the boiler flue gas in the ductwork between the air heater and the particulate collection device. The sulfite/sulfate salts reaction products are then removed by a downstream PM control device. Since a gas/sorbent contacting vessel is not required, the DSI capital costs are lower, less physical space is required, and exhaust duct modifications are simpler compared to a dry FGD lime SDA system. However, reagent costs are higher and SO_2 control efficiencies are lower than those for dry FGD. Gulf Power noted that lime was considered as a component of the MATS rule compliance approach, but that using trona instead of lime would achieve further reductions in SO_2 emissions. Gulf Power estimated that the use of DSI with trona injection combined with lower sulfur coal would have a SO_2 removal efficiency of 48 percent corresponding to a SO_2 emissions rate of 0.74lb/MMBtu on a 30-day rolling average. Gulf Power assumed that the capital cost of DSI and the operation and maintenance costs associated with lime injection will be incurred as a MATS rule compliance plan. However, FEDP determined that the baseline should be existing conditions and conducted an independent evaluation of the cost of DSI. FDEP calculated annualized costs of approximately $2 million for Units 1 and 2, individually. Using these values and SO_2 emissions reductions of 4,175 tons for Unit 1 and 4,451 tons for Unit 2, FDEP calculated a cost-effectiveness of $477 and $435 per ton of SO_2 removed, respectively. The energy impacts associated with the DSI technology are minimal.

Dry FGD Lime SDA: The types of dry FGD systems typically installed on coal-fired boilers are those utilizing either SDA or a circulating dry scrubber (CDS). Gulf Power considered both types of control equipment and concluded that SDA and CDS present similar issues with respect to inadequate available space upstream of the existing PM control device for the installation of new equipment and the need for a larger capacity PM control device. Gulf Power considers a dry FGD lime SDA system as an inferior technology compared to wet FGD and did not further evaluate this type of dry FGD based on its conclusions that: (1) Wet FGD will achieve higher SO_2 removal, (2) dry FGD lime SDA technology is difficult to apply as a retrofit to existing boilers due to space considerations, (3) with the increased PM loading, a new PM control device will need to be installed, and (4) with the inclusion of the cost of a baghouse for the dry FGD lime SDA option, wet FGD will achieve greater emissions reductions at a lower cost compared to the dry FGD lime SDA system.

Wet FGD: Gulf Power estimated that the control effectiveness of wet FGD is 95 percent SO_2 removal for Units 1 and 2 and that the capital and annualized costs are approximately $112 million and $14.5 million, respectively, for Unit 1 and $133 million and $16.6 million, respectively, for Unit 2. Based on a removal efficiency of 95 percent, SO_2 emissions reductions would be 7,794 tons for Unit 1 and 8,256 tons for Unit 2 for a cost-effectiveness of $1,862 and $2,009 per ton, respectively. Incremental cost-effectiveness from DSI with lower sulfur coal was estimated to be $3,451 and $3,850, respectively. Gulf Power expects that wet FGD would impose an energy penalty of four MW per unit due to the increased fan power required to compensate for the higher pressure drop of the absorber vessel and that wet FGD would require substantial amounts of water and generate a wastewater stream that will require treatment.

To evaluate visibility impacts for each unit at the Saint Marks Class I area, Gulf Power conducted CALUFF modeling for each SO_2 control technology evaluated. For Unit 1, the model predicted improvements in visibility ranging from 0.37 deciview for the switch to low-sulfur coal to 0.67 deciview for wet FGD for the maximum 8th highest day for the highest year of the three years modeled, and from 0.34 deciview to 0.51 deciview, respectively, for the 22nd highest day over the three years compared to the ''existing controls'' baseline levels. Modeled visibility improvements for Unit 2 range from 0.27 deciview for the switch to low-sulfur coal to 0.61 deciview for wet FGD for the maximum 8th highest day for the highest year each of the three years modeled and from 0.24 deciview and 0.45 deciview, respectively, for the 22nd highest day over the three years modeled compared to ''existing controls'' baseline levels. The use of wet FGD instead of DSI plus low-sulfur coal results in a predicted incremental improvement in visibility of 0.19 deciview for Unit 1 and 0.22 deciview for Unit 2 for the maximum 8th highest day for the highest year of the three years modeled, and 0.07 deciview for Unit 1 and 0.09 deciview for Unit 2 for the 22nd highest day over three years. Using these modeling results and the costs identified above, the cost per deciview improvement for wet FGD is approximately $21.7 million/deciview for Unit 1 and $27.2 million/deciview for Unit 2. The incremental cost per deciview improvement for wet FGD (compared to DSI) is $178.9 million for Unit 1 and $162.8 million for Unit 2.

NO_X BART: Units 1 and 2 are equipped with LNB with high momentum injection ports, and Unit 2 uses LNBs with an overfire air control

[12] Saint Marks NWA is the only mandatory Class I federal area within the surrounding 300 km CALPUFF modeling domain used by FDEP to assess visibility impacts. The visibility impacts in the Class I areas just outside of this domain resulting from Lansing Smith emissions are expected to be lower than those predicted at Saint Marks, and EPA has determined that consideration of these impacts would not change the BART determinations.

system. In addition to LNB, both units use SNCR for additional NO_X control. Gulf Power evaluated the installation of SCR, and FDEP determined that the existing controls (LNB, overfire air system, and SNCR), along with good combustion practices, are NO_X BART for Units 1 and 2. FDEP did not select SCR as BART due to a cost-effectiveness of $5,000 per ton for Unit 1 and $7,000 per ton for Unit 2 with limited predicted visibility improvement.

SCR: As discussed above, the baseline NO_X control technology for Units 1 and 2 includes current combustion controls plus SNCR. Gulf Power estimated that the capital and annualized costs associated with SCR are approximately $66 million and $7.9 million, respectively, for Unit 1 and $74.9 million and $8.9 million, respectively, for Unit 2. FDEP assumed a control efficiency of 90 percent for SCR, resulting in NO_X emissions reductions of 1,619 tons for Unit 1 and 1,279 tons for Unit 2 for a cost-effectiveness of $4,907 and $6,957 per ton, respectively. Gulf Power provided CALPUFF modeling indicating that the installation of SCR at Unit 1 would result in a maximum visibility improvement of 0.01 deciview for the maximum 8th highest day at the St. Marks Class I area for each of the three years modeled and that there is no improvement for the 22nd highest day over the three years modeled compared to ''existing controls'' baseline levels. Furthermore, FDEP notes that baseline visibility impacts due to NO_X emissions are only 3.9 percent of the total baseline impact at the nearest Class I area. FDEP estimated that the energy impacts associated with SCR are one MW for each unit to run pumps and to overcome the high pressure drop in the systems.

PM BART: Units 1 and 2 are equipped with hot and cold side ESPs that achieve PM emissions rates of 0.014 and 0.015 lb/MMBtu. Therefore, Gulf Power conducted the PM BART analysis for only a fabric filter technology such as a baghouse. FDEP determined that the existing ESPs on Units 1 and 2 are PM BART and that no additional add-on control technologies are required for the reasons discussed below.

Fabric Filters: The collection efficiencies for fabric filter technology are approximately 99 percent for PM smaller than 2.5 microns, resulting in projected PM emissions reductions of 44 tons for Unit 1 and 37 tons for Unit 2. Gulf Power estimated that the capital and annualized costs of fabric filters are approximately $35.8 million and $4.8 million, respectively, for Unit 1 and $42.6 million and $5.6 million, respectively, for Unit 2 for a cost-effectiveness of $108,566 and $153,268 per ton of PM removed for Units 1 and 2, respectively. Gulf Power concluded that there were no modeled improvements in visibility at the nearest Class I area for both the maximum 8th highest day for each of the three years modeled and 22nd highest day over the three years modeled compared to the existing control baseline levels (i.e., visibility levels from existing ESP controls) due to the use of fabric filter technology and that the baseline visibility impacts due to PM emissions are only 1.3 percent of the total baseline impact at the nearest Class I area. Gulf Power estimated that the energy impacts associated with the fabric filter system are one MW for each unit due to the need for extra fan horsepower to overcome the increased pressure drop in the boiler exhaust system and that the higher PM removal efficiency would increase the amount of solid waste that will need to be disposed of in an onsite or offsite landfill.

Summary of FDEP's BART Determination for Gulf Power Lansing Smith:

As discussed above, FDEP has determined that the controls already in place at the current, permitted emissions limits for NO_X and PM are BART for Gulf Power's Lansing Smith Plant Units 1 and 2, and that these units will meet the SO_2 BART requirements by installing a DSI/trona system and switching to lower sulfur coal. The BART operational and emissions limiting standards for Lansing Smith Units 1 and 2 are specified in the facility's title V permit and are summarized below:

SO_2: 0.74 lb/MMBtu for Unit 1 and 0.74 lb/MMBtu for Unit 2.

NO_X: The combined NO_X emissions from Units 1 and 2 shall not exceed 4,700 tons during any consecutive 12-month rolling total as determined by CEMS data reported to the EPA Acid Rain database.

PM: Emissions shall not exceed 0.1 lb/MMBtu. Compliance is demonstrated by annual stack test.

7. FPL Turkey Point

FPL's Turkey Point facility is located in Miami-Dade County, Florida. The following Class I area is located within 300 km of the Turkey Point facility: Everglades NP–35 km. The facility consists of two residual fuel oil and natural gas-fired 440 MW fossil fuel steam EGUs (Units 1 and 2); five fuel oil-fired black start 2.75 MW diesel peaking generators supporting Units 1 and 2; a natural gas-fueled 1,150 MW combined cycle unit (Unit 5); and associated equipment. Units 1 and 2 are subject to BART and are each equipped with LNB and multi-cyclones with ash reinjection. The multi-cyclones consist of two tubular mechanical dust collector modules with 695 tubes per collector.

In 2009, FDEP issued a PM-only BART determination for Units 1 and 2 that imposed a 20 percent visible emissions limit, a 0.7 percent sulfur fuel oil restriction, and upgrades to the multi-cyclones to achieve a 0.07 lb/MMBtu PM emissions rate. FDEP assumed this would require installation of a $3.7 million ESP on each unit. In addition, the determination required FPL to conduct a PM control device additive study to determine if a 0.05 lb/MMBtu emissions rate could be achieved. FPL completed the study in 2010 showing that the lower limit was not achievable using a calcium-based additive. On September 9, 2011, FPL submitted a revised PM BART proposal to eliminate the requirement to upgrade the multi-cyclones on Unit 1 and to continue to use the existing multi-cyclone to meet a limit of 0.07 lb/MMBtu as BART for this unit based on the limited use of oil in Unit 1 and FPL's conclusions that the visibility impacts from PM are negligible and that there is little incremental visibility benefit of a new dust collector. Subsequent to the request to change the PM BART limitations, FPL submitted a new proposed BART determination to FDEP that addresses SO_2 and NO_X.

FDEP determined that Unit 1 will meet SO_2 BART by restricting the use of fuel oil to 8,760,000 MMBtu/year heat input (equivalent to a capacity factor of 25 percent) and by reducing the sulfur content of the fuel fired in Unit 1 to 0.7 percent by weight as soon as practicable but no later than December 31, 2013. These provisions have been added to state permit No. 0250003–018–AC, which is federally enforceable. This permit also requires the permanent shutdown of Unit 2 as soon as practicable but no later than December 31, 2013. FDEP also determined that the controls already in place at the current, permitted emissions limits for NO_X and PM are consistent with the original BART determination for Unit 1 made by FDEP in 2009 that required the multi-cyclones to meet a 0.07 lb/MMBtu limit for PM.

PM BART: Based on information submitted by FPL, FDEP determined that new ESPs could meet an emissions limit of 0.03 lb/MMBtu and reduce emissions from both units by a total of 1,257 tons at an estimated annualized cost of approximately $6.7 million for each ESP for a cost-effectiveness of $10,623/ton of PM removed (excluding any costs associated with any changes in construction due to the close proximity of the Turkey Point nuclear units 3 and 4). According to FPL, ESP construction for Units 1 and 2 would increase security requirements and potentially require approval from the United States Nuclear Regulatory Commission due to the proximity of Units 1 and 2 to the facility's nuclear units. FPL estimated that the energy required to operate two ESPs would be approximately 4,370 MWh per year for both units (0.13 percent of gross generation from units 1 and 2) and that 1,257 tons of ash would be generated from the ESPs requiring about 50 truck trips per year to remove it from the site for recycling or landfill disposal.

In evaluating whether to change the 2009 PM BART determination, FDEP considered the limited use of oil at Units 1 and 2 after compliance with SO_2 BART. FDEP has established a federally enforceable permit condition requiring the permanent shut down of Unit 2. FDEP is also restricting oil firing on Unit 1 to 8,760,000 MMBtu/year heat input (equivalent to a capacity factor of 25 percent). Therefore, FDEP determined that the emissions reductions from a new ESP on Unit 1 are further diminished, resulting in an even higher cost per ton of PM removed than those estimated above. As an alternative PM emissions reduction strategy, FDEP has approved the use of low sulfur residual fuel oil (0.7 percent versus the one percent sulfur oil used during the baseline period) and a reduction in the PM limit from the current allowable emissions rate of 0.1 lb/MMBtu to 0.07 lb/MMBtu, which is achievable with the existing multi-cyclones controls and the lower sulfur fuel oil. At a comparative cost of less than $3,600/ton of PM removed, FDEP considered this option cost-effective given the source's proximity to the nearest Class I area (Everglades NP) and estimated a visibility improvement of 0.6 deciview (i.e., 29 percent reduction in visibility impacts from the base case).

SO_2 BART: FPL evaluated wet and dry FGD and lower sulfur fuel oil (at 0.7 percent and 0.3 percent sulfur content) as possible SO_2 BART controls. Although technically feasible to install, FPL cites capital cost estimates of between $40 and $100 million for FGD on Units 1 and 2 and the lack of comparable units that fire gas and fuel oil with wet or dry FGD installations. FPL found no determinations for oil and gas-fired units employing FGD in EPA's RACT/BACT/LAER Clearinghouse,[13] and all of the determinations identified by FPL used lower sulfur fuel oil to reduce SO_2 emissions. FPL does not believe that a dry FGD combined with a baghouse is feasible for Units 1 and 2 since tests conducted by FPL at its Sanford power plant found that particles generated from the combustion of oil-based fuels caused considerable plugging of bags in pilot scale tests. Compared to firing natural gas, fuel oil has a significantly higher sulfur content, and FDEP has determined that limiting fuel oil firing on Unit 1 to no more than a 25 percent capacity factor and limiting the sulfur content to 0.7 percent is SO_2 BART for Unit 1.

NO_X BART: FPL evaluated SCR and SNCR as potential NO_X controls for Unit 1. FDEP determined that the limited capacity factor for fuel oil (the higher NO_X producing fuel) makes the use of add on NO_X controls economically infeasible. Unit 1 is currently required to meet an emissions limit of 0.40 lb/MMBtu on gas and 0.53 lb/MMBtu on fuel oil based on a 30-day rolling average and CEMS to satisfy Florida Rule 62–296.570 for NO_X reasonably available control technology (RACT). Since Unit 2 is required to permanently shut down, FPL did not perform a control evaluation for Unit 2. Further, the baseline modeling showed that nitrates contributed less than three percent of the visibility degradation associated with the emissions from this facility.

Summary of FDEP's BART Determination for FPL Turkey Point: Permit No. 0250003–018–AC requires FPL to permanently shut down Unit 2 as soon as practicable but no later than December 31, 2013. This permit is federally enforceable. For Unit 1, FDEP has determined that NO_X BART are the controls already in place at the current, permitted emissions limits and for PM and SO_2, BART is the restricted use of fuel oil to 8,760,000 MMBtu/year heat input (equivalent to a capacity factor of 25 percent). The BART operational and emissions limiting standards for FPL Turkey Point Unit 1 are summarized below:

SO_2: As soon as practicable, but not later than December 31, 2013, the sulfur content of the fuel fired in Unit 1 shall not exceed 0.7 percent, by weight and SO_2 emissions from Unit 1 shall not exceed 0.77 lb/MMBtu on a three-hour rolling average. Compliance shall be demonstrated through the use of the existing CEMS.

NO_X: NO_X emissions from Unit 1 shall not exceed the following limits based on a 30-day rolling average: 0.40 lb/MMBtu and 1,610 lb/hour when burning gas and 0.53 lb/MMBtu and 2,041 lb/hour when burning oil.

PM: Emissions of PM are limited to 0.07 lb/MMBtu when firing fuel oil. Limits will be met by firing natural gas, co-firing natural gas with fuel oil containing less than 0.7 percent sulfur, and through the use of multi-cyclones (mechanical dust collectors) and fly ash reinjection. Compliance will be demonstrated by stack tests when fuel oil is fired for more than 400 hours annually.

8. PEF Crystal River

PEF's Crystal River Power Plant is located in Citrus County, Florida. The following Class I areas are located within 300 km of the Crystal River Plant: Saints Marks NWA–174 km, Chassahowitzka NWA–21 km, Wolf Island NWA–293 km, and Okefenokee NWA–178 km. The facility consists of four coal-fired EGUs and associated equipment. Units 1 and 2 are subject to BART and NSPS subpart Da. These units are tangentially-fired, dry-bottom boilers with a nominal generation capacity of 440.5 and 523.8 MW, respectively, that may burn bituminous coal or a bituminous coal and bituminous coal briquette mixture. Distillate fuel oil may be burned as a startup fuel. Each unit has an ESP to control PM and LNB to control NO_X and is equipped with CEMS to measure and record NO_X and SO_2 emissions and a continuous opacity monitoring system to measure and record the opacity of the exhaust gases.

PEF has proposed to satisfy SO_2 and NO_X BART requirements through an approach that would allow the company to select one of two compliance options. The first option would require the installation of a dry FGD and SCR to these units by 2018 and would extend the life of these units. The second option would shut down these units by December 31, 2020, with no new controls being installed. PEF has requested that it have until January 1, 2015, to state which option it will pursue because it is in the process of ownership change and decisions on how these units will be addressed in response to other federal regulations are uncertain. FDEP believes that either of the two options meet the BART requirements, and FDEP has allowed PEF until January 1, 2015, to choose an option. These options and the option selection date are included in a federally enforceable permit.

FDEP concluded that additional control strategies for SO_2 and NO_X are not cost-effective if the units shutdown by December 31, 2020. Should PEF choose not to shut down Units 1 and 2,

[13] EPA's RACT/BACT/LAER Clearinghouse is located at: *http://cfpub.epa.gov/RBLC/index.cfm?action=Home.Home&lang=en.*

Option 2 of the permit requires PEF to install dry FGD to meet an emissions limit of 0.15 lb/MMBtu on a 30-day rolling average, or 95 percent control efficiency, and SCR to achieve 90 percent removal efficiency by January 1, 2018.

For PM BART, FDEP determined that a PM limitation of 0.04 lb/MMBtu for the combined units is PM BART. A federally enforceable PM BART permit was issued for Units 1 and 2 on February 25, 2009 (Permit No. 0170004–017–AC), which imposed this revised allowable PM emissions limit. In this earlier BART determination, PEF proposed to upgrade the existing ESP for Unit 2 to reduce the allowable PM limit from 0.1 lb/MMBtu to 0.04 lb/MMBtu (average for both units), and to permanently cease operating the units as coal-fired boilers by the end of the year 2020. FDEP determined that additional PM control, beyond 0.04 lb/MMBtu, is not necessary for BART given the control costs associated with the limited visibility improvement resulting from a more stringent limit. In the latest issued permit for SO_2 and NO_X BART, FDEP recognized that under the option to continue operation, the installation of a dry FGD system will necessitate additional PM control to avoid significant emissions increases. Therefore, FDEP will limit PM emissions to 0.015 lb/MMBtu at both units should PEF select the SO_2 control technology option to satisfy SO_2 BART.

SO_2 BART: The facility currently burns 1.02 percent sulfur coal and has a baseline emissions rate of 38,250 tons per year of SO_2. PEF evaluated three options for SO_2 control: (1) Switch to lower sulfur coal, (2) dry FGD lime SDA, and (3) wet FGD. All of these available retrofit SO_2 control technologies are technically feasible for Units 1 and 2. However, FDEP determined that switching to a lower sulfur fuel or installing an FGD system is not cost-effective if PEF retires the units by December 31, 2020. Without this retirement date, FDEP determined that a SO_2 emissions rate of 0.15 lb/MMBtu on a 30-day rolling average, or 95 percent control efficiency, is SO_2 BART and can be achieved through the use of controls such as dry FGD.

Low Sulfur Coal: Units 1 and 2 currently burn bituminous coal, a bituminous coal and bituminous coal briquette mixture, distillate fuel oil, or on-specification used fuel oil. Distillate fuel oil is only used during start-up and flame stabilization. PEF evaluated the use of lower sulfur coal in Units 1 and 2 and indicated that bituminous coal with a sulfur content of 0.68 percent and sub-bituminous coal with a sulfur content of 0.35 percent from the PRB are commercially available. For the low sulfur coal control options, PEF assumed that an ESP upgrade would be necessary to accommodate the 0.68 percent sulfur coal, and a replacement of the ESPs with baghouses and modification of other equipment would be required to fire the 0.35 percent PRB coal. For this analysis, PEF assumed that ESP upgrades or ESP replacement and other equipment modifications would not be complete until 2018. PEF estimated costs at approximately $155 million in capital expenditures to switch the units to 0.68 percent sulfur fuel based on an ESP upgrade with annualized costs of $97.5 million assuming closure in 2020. PEF estimated capital costs of approximately $516 million and annualized costs of $297 million for the 0.35 percent sulfur fuel considering cost factors including performance, coal handling performance, and safety for 0.35 percent coal and the replacement of an ESP with a baghouse. The estimated annual SO_2 reductions are 12,250 and 20,250 tons per year, respectively, resulting in cost-effectiveness estimates of $8,665 and $14,652 per ton of SO_2 removed, respectively. PEF states that energy impacts (derating of the power generating capability of the units) would likely be associated with the use of PRB coal due to the lower heating values compared to the current coal used in Units 1 and 2. The heating values of the coal currently used are approximately 12,000 British thermal units per pound (Btu/lb) compared to the heating value of 8,500 Btu/lb for PRB coal.

Wet FGD or Dry FGD Lime SDA: PEF evaluated the potential use of wet and dry FGD on Units 1 and 2 to reduce SO_2 emissions, assuming a control efficiency of 95 percent. PEF discusses SDA control equipment but states that the installation of the technology is a concern due to inadequate available space and the conditions of the units and that the installation of dry FGDs would also necessitate additional PM control to prevent significant emissions increases. The PEF analysis states that the control efficiency of a wet FGD system is between 56 and 98 percent and the control efficiency of a dry FGD is between 70 and 96 percent.

FDEP estimated that the capital costs for installation of dry FGD systems are approximately $445 million for Units 1 and 2, combined, with a total annualized cost for installation and operation of the dry FGD systems of $364 million for a cost-effectiveness of over $10,000 per ton of SO_2 removed. These annualized costs represent the annualized capital cost as well as recurring annual operating costs for each unit assuming the facility shuts down in 2020. PEF determined that the operation of dry FGD imposes an energy penalty due to the increased fan power required to compensate for the higher pressure drop of the absorber vessel and that it would have non-air quality environmental impacts due to the generation of additional solids. For a wet FGD, non-air quality environmental impacts would include increased energy use, increased water use, and the generation of additional solid wastes.

NO_X BART: PEF identified SCR and SNCR as technically feasible options for Units 1 and 2 and noted that although there are examples where SNCR is installed on coal-fired boilers, this technology is more common for smaller boilers in the 100 MW size range. For large pulverized coal fired boilers, PEF regards SCR as a demonstrated technology and SNCR as not demonstrated. FDEP concluded that the existing combustion process, LNBs, and use of good combustion practices are NO_X BART for Units 1 and 2 under the option to shut down these units by December 31, 2020. Should PEF choose not to shut down these units, the permit establishes a NO_X emissions limit of 0.09 lb/MMBtu on a 30-boiler operating day rolling average basis. The emissions standard will be achieved by the installation and operation of NO_X control systems including SCR before January 1, 2018, or within five years of EPA's final approval of Florida's final regional haze SIP, whichever is later.

SCR: PEF states that the control effectiveness of SCR technology can be up to 90 percent. Assuming that the facility shuts down in 2020, FDEP estimated annualized costs of approximately $92.6 million and a cost-effectiveness of $8,244 per ton of NO_X removed using the methodology in EPA's *Air Pollution Control Cost Manual* (*http://www.epa.gov/ttncatc1/products.html#cccinfo*). The cost-effectiveness was estimated based on 90 percent control of baseline emissions of 12,480 tons (i.e., 11,232 tons of reduction of NO_X), which was determined from the maximum annual actual emissions for Units 1 and 2 combined from the period 2001–2003. Annual costs were developed based on a capital cost of $193/kilowatt (kW) and a fixed operation and maintenance cost of $0.7/kW. CALPUFF modeling indicates that SCR would improve visibility by 1.71 deciviews at the nearest Class I area (Chassahowitzka NWA) for the maximum 8th high day (2003) for a visibility cost-effectiveness of $54.2 million/deciview. PEF estimates that the installation of SCR will result in a power requirement of approximately 0.6 percent (50,700 MWh per year) due to the backpressure of the SCR catalyst and auxiliary equipment, and that there would be some non-air quality environmental impacts associated with the storage and handling of ammonia. PEF indicated that ammonia slip is an issue with both SCR and SNCR operation due to odor and ammonium salt formation. If urea is used with these control technologies, water treatment would be required.

SNCR: PEF evaluated SNCR for Units 1 and 2 using a control effectiveness of approximately 25 percent and a capital cost of $19/kW and fixed operation and maintenance cost of $0.2/kW. FPL conservatively estimated an annualized cost of $8.4 million for a cost-effectiveness of $2,687 per ton of NO_X removed. CALPUFF modeling predicts a visibility improvement of 0.47 deciview at the Chassahowitzka NWA for the maximum 8th high day (2003) from SNCR on both units for a visibility cost-effectiveness of approximately $17.7 million/deciview. If SNCR is installed, PEF states that additional electrical power will be required to operate the reagent handling system and that a water treatment system will be required if urea is used as a reagent, which will also need additional power. PEF also indicated that ammonia slip is an issue with SNCR operation, as discussed above.

PM BART: CALPUFF modeling indicates that replacing the existing ESPs with new control devices (i.e., new ESP or baghouse) designed to meet an emissions limit of 0.015 lb/MMBtu would improve visibility by a maximum of 0.15 deciview (based on the maximum 8th highest 24-hour average of each of the three years modeled) at the nearest Class I area. PEF also estimated that the capital cost of upgrading the existing PM controls or replacing them with new control devices would range from $71 million to $144 million. Considering the age of the units and the cost of replacing the ESPs, PEF proposed to upgrade the existing ESP for Unit 2, reduce the allowable PM limit from 0.1 lb/MMBtu to 0.04 lb/MMBtu (average for both units), and to permanently cease operating the units as coal-fired boilers by December 31, 2020. FDEP determined that meeting an emissions standard of 0.015 lb/MMBtu can be achieved by all proposed options. However, FDEP concluded that it is not reasonable to require the capital expenditure needed to bring emissions down to levels achievable by new units and control devices given the limited remaining useful life. Therefore, FDEP determined that reducing PM emissions from the current allowable emissions limit of 0.1 lb/MMBtu to levels near what has been reported in stack tests over the past five years (0.04 lb/MMBtu) with a commitment to cease operating these units as coal-fired boilers by December 31, 2020, is BART. Should PEF choose not to shut down Units 1 and 2, it must install SO_2 control technology. The SO_2 BART determination (Permit No. 0170004–036–AC) includes a requirement that no later than January 1, 2018, or within five years of the effective date of EPA's approval of this specific requirement in the Florida regional haze SIP, whichever is later, PM emissions shall not exceed 0.015 lb/MMBtu, as determined by EPA Method 5.

Summary of FDEP's BART Determination for PEF Crystal River: As discussed above, FDEP has determined that if these units are shutdown by December 31, 2020, additional control strategies for SO_2 and NO_X are not cost-effective and a PM limitation of 0.04 lb/MMBtu for the combined two units is deemed to be BART. Should PEF choose not to shutdown Units 1 and 2, PEF must install SO_2 and NO_X control technology to meet the limits as specified in the permit and summarized below, by January 1, 2018. However, the permit authorizing PEF to construct the SO_2 control, should that option be selected, assumes that this control will be a dry FGD and limits PM to 0.015 lb/MMBtu at both units. FDEP has allowed PEF until January 1, 2015, to choose the BART option that it wishes to follow. Under the option to shutdown by December 31, 2020, BART is compliance with the following operational and emissions limiting standards:

SO_2: Existing controls for Units 1 and 2. (Permit No. 0170004–017–AC.)

NO_X: Existing controls for Units 1 and 2. (Permit No. 0170004–017–AC.)

PM: 0.04 lb/MMBtu for combined emissions from Units 1 and 2. Compliance demonstrated by stack test.

Under the option to continue operation of Units 1 and 2, BART is compliance with the following operational and emissions limiting standards:

SO_2: 0.15 lb/MMBtu or 95 percent reduction for Units 1 and 2

NO_X: 0.09 lb/MMBtu for Units 1 and 2

PM: 0.015 lb/MMBtu for combined emissions from Units 1 and 2. Compliance demonstration by a stack test.

9. EPA Assessment of BART Determinations

EPA proposes to approve Florida's BART analyses and determinations for the units identified above because the analyses were conducted in a manner that is consistent with EPA's BART Guidelines and EPA's *Air Pollution Control Cost Manual* and because Florida's conclusions reflect a reasonable application of EPA's guidance to these sources.

C. Reliance on CAIR

Although Florida no longer relies on CAIR to satisfy regional haze requirements for any sources within the State, the underlying emissions inventories and projections of reductions from upwind states continue to include assumptions based on the implementation of CAIR. Given the requirement in 40 CFR 51.308(d)(1)(vi) that states must take into account the visibility improvement that is expected to result from the implementation of other CAA requirements, Florida based its RPGs, in part, on the emissions reductions expected to be achieved by CAIR and other measures being implemented across the southeast region as modeled for Florida by the Visibility Improvement State and Tribal Association of the Southeast (VISTAS).[14] As CAIR has been remanded by the DC Circuit, some of the assumptions underlying the development of this element of the RPGs may change. EPA is proposing to determine that this reliance on CAIR in upwind states in the underlying analysis does not require EPA to withhold full approval of Florida's regional haze SIP.

As explained above, the 2008 remand of CAIR was followed by a 2012 decision in *EME Homer Generation, L.P.* v. *EPA,* No. 11–1302 (DC Cir., August 21, 2012), to vacate the Transport Rule and keep CAIR in place pending the promulgation of a valid replacement rule. In this unique circumstance, EPA believes that full approval of the SIP submission is appropriate. To the extent that Florida is relying on emissions reductions associated with the implementation of CAIR in other states in its regional haze SIP, the recent

[14] The VISTAS Regional Planning Organization (RPO) is a collaborative effort of state governments, tribal governments, and various federal agencies established to initiate and coordinate activities associated with the management of regional haze, visibility and other air quality issues in the southeastern United States. Member state and tribal governments include: Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, West Virginia, and the Eastern Band of the Cherokee Indians.

directive from the DC Circuit in *EME Homer* ensures that the reductions associated with CAIR will be sufficiently permanent and enforceable for the necessary time period. EPA has been ordered by the court to develop a new rule and the opinion makes clear that after promulgating that new rule, EPA must provide states an opportunity to draft and submit SIPs to implement that rule. Thus, CAIR cannot be replaced until EPA has promulgated a final rule through a notice-and-comment rulemaking process, states have had an opportunity to draft and submit regional haze SIPs, EPA has reviewed the SIPs to determine if they can be approved, and EPA has taken action on the SIPs, including promulgating a federal implementation plan if appropriate. These steps alone will take many years, even with EPA and the states acting expeditiously. The court's clear instruction to EPA that it must continue to administer CAIR until a ''valid replacement'' exists provides an additional backstop; by definition, any rule that replaces CAIR and meets the court's direction would require upwind states to eliminate significant downwind contributions.

Further, in vacating the Transport Rule and requiring EPA to continue administering CAIR, the DC Circuit emphasized that the consequences of vacating CAIR ''might be more severe now in light of the reliance interests accumulated over the intervening four years.'' *EME Homer,* slip op. at 60. The accumulated reliance interests include the interests of states who reasonably assumed they could rely on reductions associated with CAIR to meet certain regional haze requirements. For these reasons also, EPA believes it is appropriate to allow Florida to rely on reductions associated with CAIR in other states as sufficiently permanent and enforceable pending a valid replacement rule for purposes such as evaluating RPGs in the regional haze program. Following promulgation of the replacement rule, EPA will review regional haze SIPs as appropriate to identify whether there are any issues that need to be addressed.

Finally, unlike the enforceable emissions limitations and other enforceable measures in the LTS, RPGs are not directly enforceable. *See* 64 FR 35733, 40 CFR 51.308(d)(1)(v). The data provided by Florida indicate that EPA can reasonably expect the projected SO_2 emissions reductions in 2018 to be sufficient to meet the projected RPGs. As noted in the May 25, 2012, proposal, EPA believes that the five-year progress report is the appropriate time to address any changes, if necessary, to the RPG demonstration and/or the LTS. EPA expects that this demonstration will address the impacts on the RPGs of any needed adjustments to the projected 2018 emissions due to updated information on the emissions for EGUs and other sources and source categories. If this assessment determines that an adjustment to the regional haze plan is necessary, EPA regulations require a SIP revision within a year of the five-year progress report. *See* 40 CFR 51.308(h)(4).

IV. What action is EPA taking?

EPA is proposing a full approval of the BART and reasonable progress determinations identified in Tables 1 and 2, above. In addition, EPA proposes to find that Florida's September 17, 2012, regional haze SIP amendment corrects the deficiencies that led to the proposed May 25, 2012, limited approval and proposed December 30, 2011, limited disapproval of the State's entire regional haze SIP and that Florida's regional haze SIP now meets all of the applicable regional haze requirements as set forth in sections 169A and 169B of the CAA and in 40 CFR 51.300–308. EPA is therefore withdrawing the previously proposed limited disapproval of Florida's entire regional haze SIP and is now proposing full approval.

V. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the Act and applicable federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. Accordingly, this proposed action merely approves state law as meeting federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this proposed action:

- Is not a ''significant regulatory action'' subject to review by the Office of Management and Budget under Executive Order 12866 (58 FR 51735, October 4, 1993);
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Does not have Federalism implications as specified in Executive Order 13132 (64 F43255, August 10, 1999);
- Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- Is not subject to requirements of Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA; and
- Does not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, this proposed rule does not have tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), because the SIP is not approved to apply in Indian country located in the state, and EPA notes that it will not impose substantial direct costs on tribal governments or preempt tribal law.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Intergovernmental relations, Nitrogen oxides, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide, Volatile organic compounds.

Authority: 42 U.S.C. 7401 *et seq.*

Dated: November 30, 2012.

A. Stanley Meiburg,

Acting Regional Administrator, Region 4.

[FR Doc. 2012–29764 Filed 12–7–12; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R03–OAR–2010–0143; FRL–9759–5]

Approval and Promulgation of Air Quality Implementation Plans; Maryland; the 2002 Base Year Inventory for the Baltimore, MD Nonattainment Area for the 1997 Fine Particulate Matter National Ambient Air Quality Standard

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.