BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

An Operating Permit for the Scherer Steam-Electric Generating Plant, Monroe County, Georgia.	Source I.D. 04-13-207-00008
	Permit No. 4911-207-0008-V-03-0
Proposed by the Georgia Environmental Protection Division.	
	Petition No. V-2012-_____

PETITION REQUESTING THAT THE ADMINISTRATOR OBJECT TO ISSUANCE OF THE PROPOSED TITLE V OPERATING PERMIT FOR THE SCHERER POWER PLANT

Pursuant to Clean Air Act § 505(b)(2) and 40 CFR § 70.8(d), the Sierra Club petitions the Administrator of the United States Environmental Protection Agency ("U.S. EPA" or "EPA") to object to a proposed Title V Operating Permit for the Scherer Steam-Electric Generating Plant ("Scherer"), Permit Number 4911-207-0008-V-03-0 ("Permit"). The Permit was proposed to U.S. EPA by the Georgia Environmental Protection Division ("GEPD") more than 45 days ago. A copy of the proposed Permit is attached as Exhibit A.

Sierra Club provided comments to the GEPD on the draft permit and the revised draft permit. A copy of Sierra Club's comments is attached at Exhibit B. GEPD's Statement of Basis (labeled as an Amended Narrative) ("Amended Narrative") including response to comments, is attached as Exhibit C. To

Petitioner's knowledge, EPA has not yet objected to the proposed Permit. *See* http://www.epa.gov/region4/air/permits/#Part70 (last visited June 12, 2012).

This Petition is filed within sixty days following the end of U.S. EPA's 45-day review period, as required by Clean Air Act ("CAA") § 505(b)(2).[1] The Administrator must grant or deny this petition within sixty days after it is filed. 42 U.S.C. § 7661d.(b)(2). If the Administrator determines that the Permit does not comply with the requirements of the CAA, or fails to include any "applicable requirement," she must object to issuance of the permit. 42 U.S.C. § 7661b(b); 40 C.F.R. § 70.8(c)(1) ("The [U.S. EPA] Administrator will object to the issuance of any proposed permit determined by the Administrator not to be in compliance with applicable requirements or requirements under this part."). "Applicable requirements" include, *inter alia*, any provision of the Georgia State Implementation Plan ("SIP"), including any term or condition of any preconstruction permit, any standard or requirement under Clean Air Act sections 111, 112, 114(a)(3), or 504, and acid rain program requirements. 40 C.F.R. § 70.2; *In the Matter of Wisconsin Power and Light Columbia Generating Station*, Petition Number 2008-1, Order Responding to Petitioner's Request that the Administrator Object to Issuance of State Operating Permit, at 5, 10 ("Columbia Generating Station"). Additionally, because this Petition establishes that the Permit fails to assure compliance with applicable requirements and contains material errors and inaccurate or unclear statements,

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[1] EPA's forty-five (45) day comment period expired on April 14, 2012. The public's time for petitioning the Administrator extends through, at least, June 13, 2012. EPA's List of Georgia Proposed Title V Permits, *available at* http://www.epa.gov/region4/air/permits/georgia.htm (last accessed June 12, 2012) (attached at Exhibit D)

EPA must reopen and revise the permit pursuant to 42 U.S.C. § 7661d(e) and 40 CFR §§ 70.7(g) and 70.8.

As set forth below, the Administrator should object to the Permit for the following reasons:

1. The Permit does not contain required limitations resulting from modifications that have triggered prevention of significant deterioration ("PSD") and non-attainment new source review ("NA-NSR"), and GEPD failed to provide a reasoned analysis of why PSD and NA-NSR are not applicable from the turbine project at Scherer. As a result, the Permit fails to include applicable limitations required under Title V.
2. The Permit lacks sufficient monitoring to assure compliance for particulate matter ("PM") emissions. By concluding that no better than once-every-five-year stack testing was sufficient to assure compliance, by failing to provide rationale supporting this decision, and by failing to include any additional or alternative particulate matter monitoring sufficient to provide reliable data sufficient to determine compliance on a continuous basis, GEPD failed to meet the minimum monitoring requirements under Title V and Part 70.
3. The Permit lacks sufficient monitoring to assure compliance for SO_2. By including language that may exempt the facility from continuous emissions monitoring systems ("CEMS") operation during startup, shutdown, and malfunction periods, and by responding with inadequate discussion on this issue that further confuses the issue by stating that recording of information is not required during these periods, GEPD failed to meet the minimum monitoring requirements under Title V and Part 70.
4. The Permit contains inadequate provisions addressing hazardous air pollutants ("HAPs") under recently promulgated regulations. GEPD failed to include detailed information as to how the facility must comply with these regulations. As a result, the Permit fails to include applicable limitations.
5. The Permit contains inadequate provisions addressing fugitive dust from the coal handling systems. By failing to include specifically enforceable best management practices, GEPD has ignored the language of its SIP. As a result, the Permit fails to include these practices to limit fugitive emissions.

I. The Permit Must Include Limitations to Comply with both PSD and NA-NSR.

Sierra Club commented on the planned construction in 2012 and 2013 of steam turbine upgrades for each of the four units at Plant Scherer, a modification that triggers PSD and NA-NSR, and should result in additional limitations within the permit. Comments at section IV. However, GEPD's responses to these comments do not adequately address the concerns raised by Sierra Club, and as a result, EPA should object and reopen the permit to include limitations based on PSD and NA-NSR.

A. Regulatory Background on PSD and NA-NSR.

All sources subject to Title V must have a permit to operate that "assures compliance by the source with all applicable requirements." See 40 C.F.R. § 70.1 (b)(2011); Clean Air Act § 504(a), 42 U.S.C. § 7661c. To meet this requirement, every Title V permit application must provide "a description of all applicable requirements" and must disclose any violations at the facility. *See* 42 U.S.C. § 7661b(b); 40 C.F.R. §§ 70.5(c)(4)(I), (5), (8).

Georgia and federal law define "applicable requirements" to include "any standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under Title I of the Act that implements the relevant requirements of the Act, including any revisions to that plan promulgated in 40 CFR part 52." 40 C.F.R. § 70.2 (incorporated by reference by Ga. Compo R. & Regs. r. 391-3-1-.03(10)(a)4). This definition encompasses the requirement for new and modified major stationary sources to obtain PSD permits that fully comply with all applicable PSD requirements under the Act and the Georgia SIP, including the requirements to apply best available control technology ("BACT") and to perform air quality demonstrations. *See generally* CAA 110(a)(2)(C), 160-69, 173; 40 C.F.R. §§ 2.21 *et seq.*

The Georgia SIP incorporates by reference the federal PSD regulations set forth at 40 C.F.R., Part 52.21, as amended. *See* Ga. Comp. R. & Regs. r. 391-3-1-.02(7). Under applicable regulations, PSD provisions are triggered when "a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases—a significant emissions increase . . . , and a significant net emissions increase. . . " of a regulated NSR pollutant. 40 C.F.R. § 52.21(a)(2)(iv)(a). This is a two-step analysis.

i. Significant Emissions Increase

In order to determine whether a significant emissions increase will occur as of the result of a project, the change in emissions must be calculated, and then compared with established thresholds of significance.

The change in emissions for existing emissions units are calculated through the "actual-to-projected-actual" test, requiring comparison between baseline actual emissions to projected actual emissions or the unit's potential to emit. 40 C.F.R. § 52.21(a)(2)(iv)(c); *see also,* Draft Georgia EPD PSD Permit Application Guidance Document (June 2012) ("Draft GEPD PSD Guidance"), *available at* http://www.georgiaair.org/airpermit/html/sspp/psdresources.htm (last accessed June 10, 2012). This analysis can be summarized by the following equations:

BE – A = BAE
DG – BAE = EE
PE – EE = PAE
PAE – BAE = Change in Emissions [OR PTE – BAE = Change in Emissions]

Where:
BE = Baseline emissions (zero for new units; for existing units,

	annual emissions from any 24-month period chosen by the source during the relevant look-back period)
A =	Adjustments that must be made to BAE for existing units (to account for any noncompliant emissions, new emissions limitations with which the source must currently comply, and permanent changes in basic design parameters)
BAE =	Baseline Actual Emissions
PE =	Project Emissions (PTE for new units; for existing units, future highest 12-month period of emissions projected, before excluding demand growth)
DG =	Demand Growth Emissions (zero for new units; for existing units, projected changes in emissions that the unit could have accommodated during baseline period and that are unrelated to the project)
EE =	Excludable emissions. Emissions excluded from the project emissions as they could have been accommodated during the baseline and are unrelated to the project.
PAE =	Projected Actual Emissions
[PTE =	Potential to Emit]

Draft GEPD PSD Guidance at 2-8 – 2-9; 40 C.F.R. § 52.21(a)(2)(iv)(c), (b)(41), (b)(48)(i), and (b)(48)(ii). Notably, in calculating the Baseline Actual Emissions, the permittee and permitting authority must adjust annual emissions <u>downward</u> to incorporate any binding limitations that have occurred between the dates selected and the date the facility commences construction. *See* Draft GEPD PSD Guidance at 2-6; *See also* Approval and Promulgation of Air Quality Implementation Plans; Colorado; Revisions to New Source Review Rules, 77 Fed. Reg. 21453, 21467 (April 12, 2012) *quoting* 2002 Final NSR Improvement Rules (Nov. 21, 2002) *available at* http://epa.gov/nsr/documents/nsr-analysis.pdf (last accessed June 12, 2012) ("[A] source cannot qualify for a significantly higher baseline emissions level if the present emissions are lower as a result of enforceable controls or other enforceable limitations that have gone into effect since that time.")

In order to determine whether PSD is applicable to a source, the calculated emissions change must be compared with significance thresholds found in 40 C.F.R. 52.21(b)(23). If a particular project increases emissions above this threshold, a significant emissions increase is present, and the analysis continues to the next step.

ii. Significant Net Emissions Increase

A "net emissions increase" involves an arithmetic determination of whether a project will result in an emissions increase by adding all the emissions increases that will result from a project and then adding and/or subtracting all contemporaneous, creditable emission increases and emission decreases. The contemporaneous period is defined in the regulations as beginning on the date five years before construction commences on a change and ending on the date the increase from the change occurs. 40 C.F.R. § 52.21(b)(3)(ii). A decrease in actual emissions is creditable only to the extent that, among other things, "[i]t is enforceable as a practical matter at and after the time that actual construction on the particular change begins" and "[i]t has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular Change[.]" 40 C.F.R. § 52.21(b)(3)(vi)(b) & (c).

B. Georgia Power's Calculations to Determine PSD Applicability Are Incorrect.

As Sierra Club pointed out in its comments, it appears that Georgia Power incorrectly collapsed both the significant emissions increase and significant net emissions increase steps into one step.[2] Comments at 10-12. At the very least, there is inadequate information to determine whether the Title V permit requires addition of PSD requirements. However, because it appears that Georgia Power incorporated incorrect emissions reductions into its collapsed version, it is likely that a more-detailed analysis would uncover that Georgia Power's changes have resulted in triggering PSD and limitations related to that program must be incorporated into the Permit. GEPD's responses to these comments did not address these concerns, but rather improperly required additional reporting on the emissions once the project is complete, which is irrelevant to the pre-construction analysis. For these reasons, the EPA should object to Scherer's Permit.

i. Georgia Power's Calculations to Determine Significant Emissions Rate Were Incorrect.

As Sierra Club pointed out in its comments, it appears that Georgia Power took into account the effect of such other projects as the installation and operation of the SCR and scrubber systems required to be installed under Rule (sss), and the accompanying reductions in SO_2 emissions required under Rule (uuu) when calculating its emissions under the "significant emissions increase" step. Comments at 10-12. This method of calculation was improper.

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[2] As Sierra Club has previously noted, Georgia Power's emissions calculations are far from transparent. Comments at 10-12. For example, the application for the turbine upgrade at Unit 3 clearly states that NOx emissions estimates are based on "ozone season only operation of the SCR system at 0.07Ib/mmBtu." *See* Georgia SIP Air Permit Application for Plant Scherer dated March 10, 2009 (attached at Exhibit E), at Form 4.00. However, regarding SO, emissions, the application states only "CEMS, permit limit," for the method of determination of such emissions, without identifying the permit limit in question. *Id.* The only conceivable permit limit that could result in a reduction of SO, emissions from 19,825.8 tons per year (baseline) to 1,344.6 tpy (projected actual) is the Rule (uuu) limit requiring a 95 percent reduction of such emissions. If another limit is contemplated, the application does not state what it is.

As discussed above, the evaluation of significant emissions increase requires exclusion of emissions reductions that have resulted from post-data collection projects or enforceable limitations. Draft GEPD PSD Guidance at 2-8 – 2-9; 40 C.F.R. § 52.21(b)(48)(ii)(c). It accomplishes this by adjusting downward the baseline emissions by any "new emissions limitations with which the source must currently comply." Draft GEPD PSD Guidance at 2-8 – 2-9; 40 C.F.R. § 52.21(b)(48)(ii)(c). Georgia Power's calculations during step one were clearly incorrect for one of two reasons: either the limits were enforceable and should have been subtracted from the baseline emissions rate; or the emissions were not enforceable and should not have been subtracted from the final actual annual emissions post-project.

Although Sierra Club's comments pointed out that certain emissions reductions were not enforceable (discussed in the next section), either result would have made the baseline actual emissions and the projected annual emissions or potential to emit much closer, and would likely have resulted in a finding of significant emissions increase. Georgia Power would then have to evaluate whether a significant net emissions increase would occur.

However, rather than requiring Georgia Power to provide additional information, or compiling its own data and calculating whether there was a significant emissions increase, GEPD solely required additional monitoring. Amended Narrative at Addendum 5. This is incorrect under the PSD regulations, which require a complete analysis pre-construction.

ii. Georgia Power Did Not Perform a Proper Significant Net Emissions Increase Calculation.

As discussed above, a proper significant net emissions increase calculation requires "netting" all of the contemporaneous creditable emissions increases or decreases, which must be enforceable as a practical matter when the project construction begins and must be approximately the same qualitative significance for public health and welfare as that attributed to the increase from the change at the facility.

If Georgia Power took credit for decreases associated with the Rule (sss) and Rule (uuu) in determining net emissions, this was improper for at least two reasons. First, the reductions are not enforceable as a practical matter, because neither rule is enforceable during periods of allowable excess emissions (broadly defined periods of startup, shutdown and malfunction), and there is no requirement for continuous monitoring during such episodes. Second, it is not clear that such limits were or will be in effect "at and after the time that actual construction on the particular change begins." To use the planned turbine upgrade at Unit 3 as an example, construction was scheduled to commence in October 2010; in contrast, the requirements of Rule (sss) and (uuu) for that Unit would not take effect until July 1, 2011. As a result, the decreases in emissions projected from those rules taking effect are not properly creditable. As a result, the calculations must be reexamined to determine whether Georgia Power applied these incorrect reductions in its calculations.

C. The Permit Should Also Contain Provisions Under the NA-NSR Program.

The above analysis focuses on PSD applicability. Because Plant Scherer is located in an area that is nonattainment $PM_{2.5}$ (Amended Narrative at 2), the required applicability review for PM and SO_2, which contribute to $PM_{2.5}$ emissions, is properly termed "new source nonattainment" review. However, the analysis regarding whether a project constitutes a "major modification" triggering NSR review and whether the project results in a "net emissions increase," including whether decreases in actual emissions are creditable, is the same as set forth above. *See* Ga. Comp. R. & Regs. r. 391-3-1-.01 (incorporating by reference 40 C.F.R. § 51.165(a)(1)(v) (defining "major modification") and 40 C.F.R. § 51.165(a)(1)(vi) (defining "net emissions increase")).

Because the Permit inadequately addresses PSD and NA-NSR for the units affected by the modifications, the EPA should object to the Permit and order it to be revised to include such limitations. *Columbia Generating Station*, at 5, 10.

II. THE PERMIT CONTAINS INSUFFICIENT MONITORING REQUIREMENTS.

The Clean Air Act, Title V implementing regulations, and Georgia regulations mandate that Title V Permits incorporate terms sufficient to assure compliance with applicable limitations. The Permit contains insufficient monitoring requirements to assure compliance with these limitations, and for this reason the EPA must object to the Permit and revise to include sufficient monitoring requirements.

The CAA requires that permits "shall set forth . . . monitoring . . . requirements sufficient to assure compliance" with emissions limits in a Title V permit. 42 U.S.C. § 7661c(c). EPA has promulgated regulations in Part 70 that describe the steps permitting authorities must take to fulfill the monitoring requirement from section 504(c). *See* 40 C.F.R. §§ 70.6(a)(3)(i)(A), 70.6(a)(3)(i)(B), and 70.6(c)(1). The D.C. Circuit in *Sierra Club v. EPA* described the Part 70 rules as requiring three steps to establish periodic monitoring requirements in each Title V permit issued:

> (1) where monitoring requirements already contained in existing regulations or permits, the permitting authority must incorporate those requirements into the permit;
>
> (2) where no previously established monitoring requirements exists for an emission limit, the permitting authority must add "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit;" and
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> (3) where monitoring requirements exist that correspond to an emission limit, but that monitoring is not sufficient to assure compliance with the permit limit, the permit writer must remedy that deficiency by supplementing inadequate monitoring to make the requirement sufficient to assure compliance.

See Sierra Club v. EPA, 536 F.3d 673, 675 (D.C. Cir. 2008); *see also In re United States Steel Corporation – Granite City Works*, Petition No. V-2009-03, Order

Responding to Petitioner's Request that the Administrator Object to Issuance of State Operating Permit, at 5-7 ("U.S. Steel").

In addition to setting forth adequate monitoring requirements for emission limits, the permitting authority is required to set forth its rationale in a statement of basis describing why the chosen monitoring regime is adequate to assure compliance with the emissions limit. 40 C.F.R § 70.7(a)(5); *U.S. Steel* at 7. The determination of what monitoring is adequate is a context-specific exercise. *U.S. Steel* at 7. EPA has described the permit writer's monitoring analysis as *beginning* by "assessing whether the monitoring required in the applicable requirement is sufficient to assure compliance with the permit terms and conditions." *Id.*

Appropriate factors for the permit writer to consider include: (1) variability of emissions from the unit in question; (2) likelihood of violation of the requirements; (3) whether add-on controls are being used for the unit to meet the emission limit; (4) the type of monitoring, process, maintenance, or control equipment data already available for the emission unit; and (5) the type and frequency of the monitoring requirements for similar emission units at other facilities. *Id.* Similarly, the *Sierra Club* court indicated that frequency of emissions monitoring must reflect the averaging time used to determine compliance. *Sierra Club*, 536 F.3d at 765 (a yearly monitoring requirement would not likely adequately address a daily maximum emission limit); *see also* U.S. EPA, Objection to Proposed Title V Operating Permit for TriGen-Colorado Energy Corporation (Sept. 13, 2000) ("a one-time test does not satisfy the periodic monitoring requirements").

Sierra Club commented on two provisions of the Scherer where monitoring requirements are insufficient to ensure compliance: the provisions requiring stack test monitoring for particulate matter ("PM"), and provisions regarding startup, shutdown and malfunction ("SSM"). Comments at sections V.c.iii, and V.d.4.

A. The Permit's PM Monitoring Provisions Must be Strengthened.

The Permit, requiring demonstration of compliance with PM limits via stack test every five years on the scrubber stack and following 8760 (or perhaps 17520) operating hours, is insufficient to assure continuous compliance with hourly PM limitations. Permit at 4.2.1. The permits should be revised to include more stringent monitoring requirements. The best option for adequate monitoring would require PM CEMS, but at a minimum the Permit must include frequent PM stack tests, e.g. quarterly, and the use of continuous parametric or surrogate monitoring with site specific correlations established during each stack test.

The PM emission standard for Scherer is derived from 40 C.F.R. § 60.42(a)(1) and Georgia Comp. R. & Regs. r. 391-3-1-.02(2)(d)2(iii), and prohibits the emission of "particulate matter in excess of 0.10 lb/MMBtu" from any steam generating unit. Permit at 5. As the Georgia SIP does not contain provisions requiring specific types of PM monitoring, and so the permitting authority must add "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." *Sierra Club,* 536 F.3d at 675; Georgia Comp. R. & Regs. r. 391-3-1-.02(2)(d)2(iii); 40 C.F.R. § 70.6(a)(3)(i)(B). Further, while the new source performance standards ("NSPS") applicable to Plant Scherer do contain PM monitoring provisions, those provisions do not provide time-periods for stack tests for on-going compliance. *See* 40 C.F.R. § 60.8. As a result, the provisions of the NSPS monitoring provisions are not adequate to assure compliance with the hourly requirements, requiring the permitting authority to "remedy that deficiency by supplementing inadequate monitoring." 40 C.F.R. § 60.8; *Sierra Club,* 536 F.3d at 675; 40 C.F.R. § 70.6(c)(1).

However, rather than provide adequate monitoring provisions, instead GEPD included a monitoring frequency that is not adequate to assure compliance with the hourly PM limits. The Permit provides that compliance with the facility's PM limit is demonstrated via stack test on the scrubber stacks every five years; and on the scrubber bypass stack following 8760 operating hours or 60 months, whichever comes first, but this may be deferred for an additional 8760 hours under certain conditions. Permit, Condition 4.2.1. Neither the Permit, nor GEPD's responses to Sierra Club's comments, provide detailed rationale as to why GEPD thinks that the chosen method is sufficient to assure compliance. *See* Permit; Amended Narrative. Rather GEPD states that there are no requirements to install CEMS and that continuous opacity monitoring systems ("COMS") are sufficient. Amended Narrative at Addendum 7. Perhaps most importantly, GEPD's response to comments completely fails to discuss, much less try to establish, a correlation between opacity limits and PM limits at the Scherer units. *Id.*

As discussed above, EPA has already found that such infrequent monitoring is insufficient to assure compliance with the limitations provided in the Permit. *U.S. Steel*. Specifically, the EPA found that PM compliance testing once every permit cycle (5 years) was facially insufficient to assure compliance with continuous limitations. *Id.* Further, the EPA found that, because the permitting authority did not provide rationale in the permit record in a "clear and documented" manner "sufficient . . . to demonstrate how the monitoring requirements in the [] permit assure compliance," the permit had to be revised to address this issue. *Id.* at 7-8.

While this analysis is squarely on point with the Permit and counsels revision of its terms, an analysis of the *U.S. Steel* factors also shows that such infrequent monitoring is unlawful. *See U.S. Steel* at 7. First, factors one and three, concerning the variability of emissions, especially as they relate to the add-on controls used by Plant Scherer, strongly indicate the necessity for continuous monitoring. The facility employs electrostactic precipitators ("ESPs") and baghouses as the means for controlling particulate matter emissions, and ESPs can be affected on an order of magnitude by a number of factors related to the fuel, flyash, and the ESP itself. Permit at 3; *See also* Declaration of Ranajit (Ron) Sahu (attached at Exhibit F).[3] Further, companies often arrange to do "diagnostic tests" before the scheduled "official stack test," which allows time to repair and clean the ESPs to ensure that the ESPs "pass" the stack test, even though particulate matter emissions may be much greater than the rest of the five-to-ten year period.

Additionally, PM CEMs are increasingly employed at other coal-fired power plants. For example, American Electric Power Company and Southwestern Power Company ("SWEPCO") have agreed to install PM CEMS at an existing coal-fired power plant. *See* American Electric Power Company, Inc. and SWEPCO Consent

[3] This declaration was created to support a Petition filed in connection with RRI Energy Mid Atlantic Power Holdings LLC, Shawville Generating Station, ID No. 17-00001. However, the type of facility and issues presented in that case are similar to the issues presented in the Scherer Permit.

Decree at 5-7. The EPA has also secured commitments from up to 30 existing coal-fired utility installations to install PM CEMS within the next few years. *See* Comment Letter Regarding Robinson Power Company Waste-Coal-Fired Power Generation Facility from David Campbell, Chief Permits and Technical Assessments Branch, United States Environmental Protection Agency Region III to Thomas Joseph, Pennsylvania Department of Environmental Protection at 6 (March 11, 2005). Given the use, reliability, and accuracy of monitoring requirements for similar emission units at other facilities, EPA should object to the Permit and require the use of PM CEMS at Scherer.

B. The Permit Should Clearly Require SO_2 CEMS Operation During All Periods of Operation except CEMS Breakdown and Repair.

Additionally, as Sierra Club noted in its comments on the Permit, it is unclear in the Permit whether operation of SO_2 CEMS is required during startup, shutdown and malfunction. Comments at section V.d.4. As the SO_2 CEMS is required in connection with SO_2 limitations, allowing the facility to cease operation of the SO_2 CEMS during such time periods would be insufficient to "assure compliance" with those limitations. Permit at conditions 3.4.15–3.4.18. Accordingly, the Permit should be revised to include language clearly requiring SO_2 CEMS operations at all times, including during startup, shutdown and malfunction.

The ambiguity results from the inclusion of a deceptively simple clause within Permit provision 5.2.21. The language of this provision appears straight-forward at first, seemingly requiring SO_2 CEMS to be "operated and data recorded during all periods of operation . . . including periods of startup, shutdown, malfunction or emergency conditions." Permit at 26. However, Condition 5.2.21 also exempts "any period allowed under Condition 3.4.19," which exempts the Plant's units from the 95% SO_2 reduction requirements of Rule (uuu) during periods of "black starts" and scheduled or preventive maintenance as well as during periods of startup, shutdown or malfunction provided such episodes are consistent with the air quality rule governing allowable "excess emissions," Rule 391-3-1-.02(2)(a)7. Permit at 12.

EPD's response to Sierra Club's comment does not address this issue, but rather provides additional confusing language, further complicating the issue. Although GEPD states that "SO_2 CEMS are required to run during all periods of operation by the Part 75 rules, including startup, shutdown, malfunction, and during emergency conditions," it then says that the plant is not required to collect data during these time periods because "they are not indicative of the scrubber control efficiency and the SO_2 reduction limits for Georgia Rule(uuu) do not apply during such periods." Amended Narrative at Addendum 8. GEPD therefore appears to require the CEMS to run during this period, but exempts the plant from data collection, rendering the CEMS useless during such periods. *Id.*

Given such confusing language and failure to address the issue by GEPD, EPA should object to the Permit and require Plant Scherer to run SO_2 CEMS during all periods (including startup, shutdown and malfunction) and to collect and record data during all periods of CEMS operation.

III. The Permit Should Include Detailed Requirements for Hazardous Air Pollutant ("HAP") Standards

As noted above, CAA 504(a) requires each Title V permit to "assure compliance with applicable requirements of this chapter, including the requirements of the applicable implementation plan [SIP]." 40 C.F.R. § 70.2 defines "applicable requirements" as including "requirements that have been promulgated or approved by EPA through rulemaking at the time of issuance but have future effective compliance dates."

On February 16, 2012, the EPA issued National Emission Standards for Hazardous Air Pollutants ("NESHAPs") for coal-fired electric steam generating units ("EGU MACT") and proposed revisions to the New Source Performance Standards ("NSPS") for these sources. This rule became effective as of April 16, 2012. Since the Scherer Permit was issued on May 8, 2012, the permit must include provisions incorporating this rule.

GEPD's response is inadequate to address the new EGU MACT. GEPD did add Condition 3.3.8 that makes a generic reference to the EGU MACT. Sierra Club was obviously not able to comment on Condition 3.3.8 during the comment period because it did not exist at that point. Having now reviewed Condition 3.3.8, we have determined that EPA should object to the Permit because it fails to include the specific requirements of the EGU MACT, and to include provisions to add any additional monitoring required by 40 C.F.R. § 70.6(c)(1).

IV. THE PERMIT MUST INCLUDE PROVISIONS TO CONTROL FUGITIVE DUST FROM THE COAL HANDLING SYSTEM.

Sierra Club's comments pointed out that the Scherer Permit does not include or meet SIP requirements because it does not include the specific, enforceable best management practices necessary to eliminate or minimize fugitive from the materials handling system. Comments at 31-32. GEPD's response to these comments only addresses requirements to record actions taken, but does not address Sierra Club's concern that the Scherer Permit only requires the plant to take "reasonable precautions" which is so vague as to be unenforceable. Amended Narrative at Addendum 9; Permit at 7.

The Scherer Permit subjects the coal handling system to an opacity limit of twenty per cent as required by Ga. Comp. R. & Regs. r. 391-3-1-.02(2)(n)2, but does not include the specific, enforceable best management practices necessary to eliminate or minimize fugitive dust from this component of the plant. The Georgia SIP includes a non-exhaustive list of specific control devices and practices that should be applied to this facility and detailed in its Title V permit as enforceable conditions of its operation. Ga. Comp. R. & Regs. r. 391-3-1-.02(2)(n). These include the application of water or other dust suppressants on surfaces or operations that can give rise to airborne dust, and "[i]nstallation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials. Ga. Comp. R. & Regs. r. 391-3-1-.02(2)(n)1.

The Permit does not include any of the listed best management practices. Permit at 7, provision 3.4.4. Rather, GPC is only required to take "reasonable precautions. *Id.* This requirement is vague and unenforceable.

In the Permit, GEPD has ignored the language of the SIP by failing to incorporate specific control devices and practices. EPA should object and require devices to be described in more detail in the Permit, and require monitoring and reporting of these devices as well as to demonstrate compliance with a 20% opacity limit, so that the public can evaluate their efficacy and, when necessary, seek enforcement of any violations. The required frequency, quantity and duration of dust suppression techniques should also be included in the Scherer Permit.

Conclusion

For the foregoing reasons, the Permit fails to meet federal requirements in numerous ways. These deficiencies require that the Administrator object to issuance of the Permit pursuant to 40 C.F.R. § 70.8(c)(1). Additionally, each of the reasons for objection, above, also constitutes a basis for mandatory reopening and revision of the Permit pursuant to 42 U.S.C. § 7661d(e), 40 C.F.R. § 70.7(g) and 70.8. Each of the issues raised by Sierra Club in this petition result in a deficient permit. Most of the deficiencies result in unlawful emissions of air pollutants that negatively affect the health and welfare of Sierra Club members. Others result in illegal monitoring and reporting that make it difficult for Sierra Club to monitor and enforce air pollution limits applicable to the plant.

Dated this 13th day of June, 2012.

Attorneys for Sierra Club

Ashten Leigh Bailey

Ashten Bailey

GREENLAW
State Bar of Georgia Building
104 Marietta Street, Suite 430
Atlanta, Georgia 30303

CERTIFICATE OF SERVICE

On this day I caused to be served upon the following persons a copy of Sierra Club's Petition to the United States Environmental Protection Agency regarding the Scherer Power Plant, Permit No. 4911-207-0008-V-03-0

To Administrator Jackson via electronic mail (without attachments) to: jackson.lisa@epa.gov

And via Certified Mail, Return Receipt Requested to:

Lisa Jackson
US EPA Administrator
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Gwendolyn Keyes Fleming
Regional Administrator, United States Environmental Protection Agency Region 4
Sam Nunn Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, GA 30303-8960

Judson H. Turner
Director, Georgia Environmental Protection Division
2 Martin Luther King Jr. Drive, SE Suite 1152 East Floyd Tower
Atlanta, GA 30334-9000

Ron Shipman
Vice President of Environmental Affairs, Georgia Power
241 Ralph McGill Blvd., NE, Bin 10221
Atlanta, GA 30308-3374

Dated: June 13, 2012.

Ashten Leigh Bailey

Ashten Bailey

Part 70 Operating Permit

Permit Number: **4911-207-0008-V-03-0** **Effective Date:** **May 8, 2012**

Facility Name: **Scherer Steam-Electric Generating Plant**

Facility Address: 10986 Highway 87
Juliette, GA 31046, Monroe County

Mailing Address: 241 Ralph McGill Blvd. NE, Bin 10221
Atlanta, GA 30308-3374

Parent/Holding Company: Southern Company/Georgia Power

Facility AIRS Number: 04-13-207-00008

In accordance with the provisions of the Georgia Air Quality Act, O.C.G.A. Section 12-9-1, et seq and the Georgia Rules for Air Quality Control, Chapter 391-3-1, adopted pursuant to and in effect under the Act, the Permittee described above is issued a Part 70 Permit for:

The operation of an electric utility plant including four steam electric generating units.

This Permit is conditioned upon compliance with all provisions of The Georgia Air Quality Act, O.C.G.A. Section 12-9-1, et seq, the Rules, Chapter 391-3-1, adopted and in effect under that Act, or any other condition of this Permit. Unless modified or revoked, this Permit expires five years after the effective date indicated above.

This Permit may be subject to revocation, suspension, modification or amendment by the Director for cause including evidence of noncompliance with any of the above, for any misrepresentation made in Title V Application No. TV-19764 signed on June 25, 2010, any other applications upon which this Permit is based, supporting data entered therein or attached thereto, or any subsequent submittal of supporting data, or for any alterations affecting the emissions from this source.

This Permit is further subject to and conditioned upon the terms, conditions, limitations, standards, or schedules contained in or specified on the attached **65** pages.

[Signed]

Director
Environmental Protection Division

EXHIBIT
A

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PART 1.0 FACILITY DESCRIPTION

1.1 Site Determination

There are no other facilities which could possibly be contiguous or adjacent and under common control.

1.2 Previous and/or Other Names

This facility is commonly known as Plant Scherer. No other names have been identified.

1.3 Overall Facility Process Description

Plant Scherer burns fossil fuel to generate electricity. This facility includes four steam electric generating units which primarily burn coal. Wet limestone Flue Gas Desulfurization (FGD) scrubbers are being installed on Steam Generating Units SG01, SG02, and SG04. An FGD scrubber is currently installed on Steam Generating Unit SG03. An 870-foot wet stack for SG01 and SG02, with separate liners for each unit is being installed. An 847-foot stack for SG03 and SG04 with separate liners for each unit is currently installed. When the FGD scrubbers are operational, during normal operation the units will exhaust through the wet stacks. There are some operations when it will be necessary to bypass the scrubbers. In these cases the units will exhaust through one of the two existing 1000-foot stacks.

PART 2.0 REQUIREMENTS PERTAINING TO THE ENTIRE FACILITY

2.1 Facility Wide Emission Caps and Operating Limits

None applicable.

2.2 Facility Wide Federal Rule Standards

None applicable

2.3 Facility Wide SIP Rule Standards

None applicable.

2.4 Facility Wide Standards Not Covered by a Federal or SIP Rule and Not Instituted as an Emission Cap or Operating Limit

None applicable.

PART 3.0 REQUIREMENTS FOR EMISSION UNITS

Note: Except where an applicable requirement specifically states otherwise, the averaging times of any of the Emissions Limitations or Standards included in this permit are tied to or based on the run time(s) specified for the applicable reference test method(s) or procedures required for demonstrating compliance.

3.1 Emission Units

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	Description	Applicable Requirements/Standards	Corresponding Permit Conditions	ID No.	Description
SG01	Steam Generator Unit 1	391-3-1-.02(2)(b), (d), (g), (jjj), (sss), (uuu) 40 CFR 60 Subpart A, 40 CFR 60 Subpart D, Acid Rain and CAIR 40 CFR 63 Subpart A 40 CFR 63 Subpart UUUUU	3.2.1, 3.2.2, 3.2.4, 3.3.1 to 3.3.5, 3.3.8, 3.4.6, 3.4.10, 3.4.11, 3.4.13, 3.4.14, 3.4.18, 3.4.19, 4.2.1, 4.2.4, 5.2.1 to 5.2.6, 5.2.10 to 5.2.24, 6.1.7, 6.2.1, 6.2.2, 6.2.7 to 6.2.10, 6.2.13 to 6.2.22, 7.9.7, 7.15.2	 SCR1 EP01 BH01 FGD1	Selective Catalytic Reduction ESP Baghouse with PAC Flue Gas Desulfurization
SG02	Steam Generator Unit 2	391-3-1-.02(2)(b), (d), (g), (jjj), (sss), (uuu) 40 CFR 60 Subpart A, 40 CFR 60 Subpart D, Acid Rain and CAIR 40 CFR 63 Subpart A 40 CFR 63 Subpart UUUUU	3.2.1, 3.2.2, 3.2.4, 3.3.1 to 3.3.5, 3.3.8, 3.4.7, 3.4.10, 3.4.11, 3.4.13, 3.4.14, 3.4.17, 3.4.19, 4.2.1, 4.2.4, 5.2.1 to 5.2.5, 5.2.7, 5.2.10 to 5.2.24, 6.1.7, 6.2.1, 6.2.2, 6.2.7 to 6.2.10, 6.2.13 to 6.2.22, 7.9.7, 7.15.2	 SCR2 EP02 BH02 FGD2	Selective Catalytic Reduction ESP Baghouse with PAC Flue Gas Desulfurization
SG03	Steam Generator Unit 3	391-3-1-.02(2)(b), (d), (g), (jjj), (sss), (uuu) 40 CFR 60 Subpart A, 40 CFR 60 Subpart D, Acid Rain and CAIR 40 CFR 63 Subpart A 40 CFR 63 Subpart UUUUU	3.2.1, 3.2.2, 3.2.4, 3.3.1 to 3.3.5, 3.3.8, 3.4.8, 3.4.10, 3.4.11, 3.4.13 to 3.4.15, 3.4.19, 4.2.1, 4.2.4, 5.2.1 to 5.2.5, 5.2.8, 5.2.10 to 5.2.24, 6.1.7, 6.2.1, 6.2.2, 6.2.7 to 6.2.10, 6.2.13 to 6.2.22, 7.9.7, 7.15.2	 SCR3 EP03 BH03 FGD3	Selective Catalytic Reduction ESP Baghouse with PAC Flue Gas Desulfurization
SG04	Steam Generator Unit 4	391-3-1-.02(2)(b), (d), (g), (jjj), (sss), (uuu) 40 CFR 60 Subpart A, 40 CFR 60 Subpart D, Acid Rain and CAIR 40 CFR 63 Subpart A 40 CFR 63 Subpart UUUUU	3.2.1, 3.2.2, 3.2.4, 3.3.1 to 3.3.5, 3.3.8, 3.4.9, 3.4.10, 3.4.11, 3.4.13, 3.4.14, 3.4.16, 3.4.19, 4.2.1, 4.2.4, 5.2.1 to 5.2.5, 5.2.9 to 5.2.24, 6.1.7, 6.2.1, 6.2.2, 6.2.7 to 6.2.10, 6.2.13 to 6.2.22, 7.9.7, 7.15.2	 SCR4 EP04 BH04 FGD4	Selective Catalytic Reduction ESP Baghouse with PAC Flue Gas Desulfurization
SB01	Start-up Boiler Unit 1	391-3-1-.02(2)(d) and (g)	3.2.3, 3.4.1, 3.4.2, 3.4.3, 6.1.7	none	n/a
SB02	Start-up Boiler Unit 2	391-3-1-.02(2)(d) and (g)	See SB01	none	n/a
CHS	Coal Handling System	40 CFR 60 Subpart A, 40 CFR 60 Subpart Y, 391-3-1-.02(2)(n)	3.3.1, 3.3.6, 3.4.4, 6.2.5	none	n/a
AHS	Ash Handling System	391-3-1-.02(2)(n)	3.4.4, 3.4.5, 3.4.6, 6.2.6	none	n/a

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	**Description**	**Applicable Requirements/Standards**	**Corresponding Permit Conditions**	**ID No.**	**Description**
MHS	Materials Handling System	391-3-1-02(2)(e) 391-3-1-.02(2)(n) 40 CFR 60 Subpart A 40 CFR 60 Subpart OOO	3.3.1, 3.3.7, 3.4.4, 3.4.5, 3.4.12, 4.2.3, 5.2.17, 6.1.7, 6.2.13	LSBA LSBB	Limestone Silo Baghouse A Limestone Silo Baghouse B

* Generally applicable requirements contained in this permit may also apply to emission units listed above. The lists of applicable requirements/standards and corresponding permit conditions are intended as a compliance tool and may not be definitive.

3.2 Equipment Emission Caps and Operating Limits

3.2.1 The Permittee shall not fire any fuel other than coal in the Plant Scherer steam generating units (Emission Unit IDs SG01, SG02, SG03, and SG04) except for the following:
[391-3-1-.03(2)(c)]

a. No. 2 fuel oil, biodiesel, or biodiesel blends may be burned for start-up, shutdown, to assist in achieving peak load, and flame stabilization.

b. Sawdust may be blended and fired with the coal.

c. Biomass may be blended and fired with the coal. Biomass, as used in this permit, shall include, but not be limited to paper, vegetative matter, or wood chips. Biomass shall not include sawdust (sawdust is covered by 3.2.1b.) or municipal solid waste except as may be specifically listed above.

d. Used oil, as indicated in Condition 3.2.2, may be burned.

e. Coal-derived synthetic fuel, manufactured using a binder with mercury of content less than or equal to 0.2 ppm on a dry basis and the binder constitutes approximately 2.5% by weight or less of the coal-derived synthetic fuel shall be considered coal for the purpose of this permit.

State Only Enforceable Condition.

3.2.2 The Permittee shall not burn used oil in any steam generating unit (Emission Unit IDs SG01, SG02, SG03, or SG04) during periods of startup or shutdown. For the purposes of this permit, startup shall be defined as the period lasting from the time the first oil fire is established in the furnace until the time that mill/burner performance and secondary air temperature are adequate to maintain an exit gas temperature above the sulfuric acid dew point. For the purpose of this permit, the term shutdown means the cessation of the operation of a source or facility for any purpose.
[391-3-1-.03(2)(c)]

3.2.3 The Permittee shall not fire any fuel other than #2 fuel oil, biodiesel, or biodiesel blends in the start-up boilers (Emission Unit IDs SB01 or SB02).
[391-3-1-.03(2)(c)]

NO_X Emission Limits for the 7-Plant Plan

3.2.4 The Permittee shall not discharge, or cause the discharge, into the atmosphere NO_X emissions, including emissions occurring during startup and shutdown, from the combined operations of all affected units (Emission Unit IDs SG01, SG02, SG03, SG04 at Plant Bowen (AFS No. 015-00011); SG01, SG02, SG03, SG04 at Plant Branch (AFS No. 237-00008); SG01, SG02, SG03, SG04 at Plant Hammond (AFS No. 115-00003); SGM1, SGM2 at Plant McDonough (AFS No. 067-00003); SG01, SG02, SG03, SG04 at Plant Scherer (AFS No. 207-00008); SG01, SG02 at Plant Wansley (AFS No. 149-00001); and SG01, SG02, SG03, SG04, SG05, SG06, SG07 at Plant Yates (AFS No. 077-00001)) in excess of 32,335.8 tons during the ozone season. For purposes of this permit, the ozone season shall be defined as May 1 through September 30.
[391-3-1-.03(8)(c)1 and 391-3-1-.03(8)(c)15]

3.3 Equipment Federal Rule Standards

3.3.1 The Permittee shall be subject to all applicable requirements of 40 CFR 60 - Standards of Performance for New Stationary Sources, Subpart A - General Provisions.
[40 CFR 60 Subpart A]

3.3.2 The Permittee shall not discharge or cause the discharge into the atmosphere from any steam generating unit (Emission Unit IDs SG01, SG02, SG03, or SG04), or steam generating source, any gases which contain particulate matter in excess of 0.10 lb/MMBtu heat input.
[40 CFR 60.42(a)(1), 391-3-1-.02(2)(d)2(iii)]

3.3.3 The Permittee shall not discharge or cause the discharge into the atmosphere from any steam generating unit (Emission Unit IDs SG01, SG02, SG03, or SG04) any gases that exhibit equal to or greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.
[40 CFR 60.42(a)(2), 391-3-1-.02(2)(d)3]

3.3.4 The Permittee shall not discharge or cause the discharge into the atmosphere from any steam generating unit (Emission Unit IDs SG01, SG02, SG03, or SG04), or steam generating source, any gases which contain sulfur dioxide in excess of 1.2 lb/MMBtu heat input.
[40 CFR 60.43(a)(2), 391-3-1-.02(2)(g)1(ii)]

3.3.5 The Permittee shall not discharge or cause the discharge into the atmosphere from any steam generating unit (Emission Unit IDs SG01, SG02, SG03, or SG04), or steam generating source, any gases which contain nitrogen oxides in excess of 0.7 lb/MMBtu heat input.
[40 CFR 60.44(a)(3), 391-3-1-.02(2)(d)4(i)]

3.3.6 The percent opacity from the coal handling system (Emission Unit ID CHS) shall not equal or exceed 20 percent.
[40 CFR 60.254(a), 391-3-1-.02(2)(n)2]

3.3.7 The Permittee shall comply with the provisions of 40 CFR 60 Subpart OOO, "Standards of Performance of Nonmetallic Mineral Processing Plants" for the affected portion of the materials handling system (Emission Unit ID MHS). The affected portion shall include any grinding mill, screening operation, belt conveyor, and storage bin associated with the limestone handling process. In particular, the Permittee shall not discharge, or cause the discharge, into the atmosphere,
[40 CFR 60 Subpart OOO]

a. from any crusher, at which a capture system is not used, any fugitive emissions which exhibit greater than 12 percent opacity.

b. from any stack, emissions which contain particulate matter in excess of 0.032 g/dscm (0.014 grains/dscf).

c. from any screening operation, belt conveyor transfer point, bagging operation, storage bin, enclosed truck or railcar loading station, or from any other affected equipment any fugitive emissions which exhibit greater than 7 percent opacity.

d. any visible emissions from;

   i. wet screening operations and subsequent screening operations, bucket elevators, and belt conveyors that process saturated material in the production line up to the next crusher, grinding mill or storage bin and,

   ii. screening operations, bucket elevators, and belt conveyors in the production line downstream of wet mining operations, where such screening operations, bucket elevators, and belt conveyors process saturated materials up to the first crusher, grinding mill, or storage bin in the production line.

For processing equipment subject to Subpart OOO located inside a building, the Permittee shall comply with the above process limits (a, b, c, and d), or shall not discharge or cause the discharge into the atmosphere, any

e. visible fugitive emissions from the building may not exhibit greater than 7 percent opacity.

f. emissions from a powered building vent which contain particulate matter in excess of 0.032 g/dscm (0.014 grains/dscf).

Note: Unloading of nonmetallic minerals from movable vehicles designed to transport nonmetallic minerals from one location to another, including but not limited to: trucks, front end loaders, skip hoists, and railcars into any screening operation, feed hopper, or crusher is exempt from the requirements of this condition.
[40 CFR 60 Subpart OOO, 40 CFR 60.672(d)]

3.3.8 The Permittee shall comply with all applicable provisions of the "National Emission Standards for Hazardous Air Pollutants" as found in 40 CFR Subpart A, "General Provisions" and 40 CFR 63, Subpart UUUUU, "National Emission Standards for Hazardous Air Pollutants from Coal and Oil-Fired Electric Utility Steam Generating Units" for operation of steam generating units (Emission Unit IDs SG01, SG02, SG03, and SG04). [40 CFR 63, Subparts A and UUUUU]

3.4 Equipment SIP Rule Standards

3.4.1 The Permittee shall not discharge or cause the discharge into the atmosphere from any startup boiler (Emission Unit IDs SB01 or SB02) any gases which contain particulate matter in excess of the rate derived from $E = 0.5 \times (10/R)^{0.5}$ where E equals the allowable particulate emission rate in pounds per million Btu heat input and R equals the heat input in million Btu per hour.
[391-3-1-.02(2)(d)2(ii)]

3.4.2 The Permittee shall not discharge or cause the discharge into the atmosphere from any startup boiler (Emission Unit IDs SB01 or SB02) any gases that exhibit equal to or greater than 20 percent opacity (6- minute average), except for one 6- minute period per hour of not more than 27 percent opacity.
[391-3-1-.02(2)(d)3]

3.4.3 The Permittee shall not fire any fuel in any start-up boiler (Emission Unit IDs SB01 or SB02) that contains greater than 3.0 percent sulfur, by weight.
[391-3-1-.02(2)(g)2]

Coal and Ash Handling Requirements

3.4.4 The Permittee shall take all reasonable precautions to prevent fugitive dust from becoming airborne from the following operations:
[391-3-1-.02(2)(n)1]

a. Coal handling system (Emission Unit ID CHS)

b. Ash handling system (Emission Unit ID AHS)

c. Materials handling system (Emission Unit ID MHS)

3.4.5 The percent opacity from the ash handling system (Emission Unit ID AHS), and materials handling system (Emission Unit ID MHS) shall not equal or exceed 20 percent.
[391-3-1-.02(2)(n)2]

NO_X Emission Limits Per Georgia Rule (jjj)

3.4.6 Except as indicated in Condition 3.4.10 and 3.4.11, the Permittee shall not discharge, or cause the discharge, into the atmosphere from steam generating unit with Emission Unit ID SG01 at Plant Scherer (AFS No. 207-00008) NO_X emissions in excess of 0.20 lb/MMBtu heat input on a 30-day rolling averaging period. This condition shall apply during the period May 1 through September 30 of each year.
[391-3-1-.02(2)(jjj)5(i) and 6(i)]

3.4.7 Except as indicated in Condition 3.4.10 and 3.4.11, the Permittee shall not discharge, or cause the discharge, into the atmosphere from steam generating unit with Emission Unit ID SG02 at Plant Scherer (AFS No. 207-00008) NO_X emissions in excess of 0.17 lb/MMBtu heat input on a 30-day rolling averaging period. This condition shall apply during the period May 1 through September 30 of each year.
[391-3-1-.02(2)(jjj)5(i) and 6(i)]

3.4.8 Except as indicated in Condition 3.4.10 and 3.4.11, the Permittee shall not discharge, or cause the discharge, into the atmosphere from steam generating unit with Emission Unit ID SG03 at Plant Scherer (AFS No. 207-00008) NO_X emissions in excess of 0.15 lb/MMBtu heat input on a 30-day rolling averaging period. This condition shall apply during the period May 1 through September 30 of each year.
[391-3-1-.02(2)(jjj)5(i) and 6(i)]

3.4.9 Except as indicated in Condition 3.4.10 and 3.4.11, the Permittee shall not discharge, or cause the discharge, into the atmosphere from steam generating unit with Emission Unit ID SG04 at Plant Scherer (AFS No. 207-00008) NO_X emissions in excess of 0.16 lb/MMBtu heat input on a 30-day rolling averaging period. This condition shall apply during the period May 1 through September 30 of each year.
[391-3-1-.02(2)(jjj)5(i) and 6(i)]

3.4.10 If the Permittee does not comply with Condition Nos. 3.4.6, 3.4.7, 3.4.8, or 3.4.9, the Permittee shall demonstrate that NO_X emissions, averaged over all affected units (Emission Unit IDs SG01, SG02, SG03 and SG04 at Plant Bowen (AFS No. 015-00011); SG01, SG02, SG03, SG04 at Plant Branch (AFS No. 237-0008); SG01, SG02, SG03, SG04 at Plant Hammond (AFS No. 115-00003); SGM1, SGM2 at Plant McDonough (AFS No. 067-00003); SG01, SG02, SG03, SG04 at Plant Scherer (AFS No. 207-00008); SG01, SG02 at Plant Wansley (AFS No. 149-00001); and SG01, SG02, SG03, SG04, SG05, SG06, SG07 at Plant Yates (AFS No. 077-00001)), do not exceed 0.18 lb/MMBtu heat input on a 30-day rolling averaging period. This condition shall apply during the period May 1 through September 30 of each year.
[391-3-1-.02(2)(jjj)5(ii)]

3.4.11 If the Permittee does not comply with Condition Nos. 3.4.6, 3.4.7, 3.4.8, or 3.4.9, the Permittee shall demonstrate that NO_X emissions, averaged over all affected units (Emission Unit IDs SG01, SG02, SG03, SG04 at Plant Scherer (AFS No. 207-00008)), do not exceed 0.17 lb/MMBtu heat input on a 30-day rolling average period. This condition shall apply during the period May 1 through September 30 of each year.
[391-3-1-.02(2)(jjj)6(ii)]

3.4.12 The Permittee shall not discharge, or cause the discharge, into the atmosphere from the Material Handling System (Emission Unit ID MHS) any gases which contain particulate matter in excess of the rate derived from the equation noted below:
[391-3-1-.02(2)(e)(1)]

a. For process input weight rate up to and including 30 tons per hour:
$E = 4.1P^{0.67}$; or

b. For process input weight rate above 30 tons per hour:
$E = 55P^{0.11} - 40$

where E equals the allowable PM emission rate in pounds per hour and P equals the total dry process input weight rate in tons per hour.

State Only Enforceable Condition.

3.4.13 The Permittee shall not operate steam generating units (Emission Unit IDs SG01, SG02, SG03, or SG04) unless such source is equipped and operated with sorbent injection and a baghouse, except the Permittee is not required to operate the required control technology under the following conditions:
[391-3-1-.02(2)(sss)]

a. Restarting an EGU when all Electric Utility Steam Generating Units [as listed in this Condition] at a facility are down and off-site power is not available (also known as a "Black Start").

b. Periods of startup of an EGU provided that such periods are consistent with the requirements outlined in the Georgia Rules for Air Quality Control 391-3-1-.02(2)(a)7.

c. Periods of shutdown of an EGU provided that such periods are consistent with the requirements outlined in the Georgia Rules for Air Quality Control 391-3-1-.02(2)(a)7.

d. Periods of scheduled and/or preventative maintenance of control technology equipment if such maintenance cannot reasonably be performed during a scheduled outage of the respective EGU.

e. Periods of malfunction of EGU and/or control technology equipment provided that such periods are consistent with the requirements of Paragraph 391-3-1-.02(2)(a)7.

f. Periods when the owner/operator is required to conduct the Relative Accuracy Test Audit and any other necessary periodic quality assurance procedures on the Continuous Emissions Monitoring System located on the bypass stack pursuant to 40 CFR Part 75 or the Georgia Department of Natural Resources ***Procedures for Testing and Monitoring Sources of Air Pollutants***.

g. Periods when the owner/operator is required to conduct any performance tests on the bypass stack as required by state or federal air quality rules, air quality operating permits, or as ordered by the Division.

h. Division approved periods of research and development of emission control technologies, provided that the unit does not exceed other applicable emission limits. For purposes of this subparagraph, the owner/operator shall submit a request for approval under this subparagraph at least 120 days prior to such date as well as including the following items: (1) length of time of research and development (R&D)

period; (2) identification of steps to take to minimize emissions in accordance with best operational practices during R&D period; (3) for periods of R&D lasting more than 48 hours during any 5-day period, a demonstration that any increase in emissions resulting from the R&D project that are above that which is allowed by this subparagraph (sss) will not cause or significantly contribute to a violation of any national ambient air quality standard or prevent compliance with any other applicable provisions.

i. Any other occasion not covered by subparagraph a. through h., as approved by the Division.

State Only Enforceable Condition.

3.4.14 For steam generating unit SG03, effective December 31, 2012 for steam generating unit SG04, effective December 31, 2013 for steam generating unit SG02, and effective December 31, 2014 for steam generating unit SG01, the Permittee shall not operate each unit unless such source is equipped and operated with selective catalytic reduction, flue gas desulfurization, sorbent injection and a baghouse; provided that the owner or operator is not required to operate the selective catalytic reduction system during the non-ozone season months of January through April and October through December of each year, and except the Permittee is not required to operate the required control technology under the following conditions:
[391-3-1-.02(2)(sss)]

a. Restarting an EGU when all Electric Utility Steam Generating Units [as listed in this Condition] at a facility are down and off-site power is not available (also known as a "Black Start").

b. Periods of startup of an EGU provided that such periods are consistent with the requirements outlined in the Georgia Rules for Air Quality Control 391-3-1-.02(2)(a)7.

c. Periods of shutdown of an EGU provided that such periods are consistent with the requirements outlined in the Georgia Rules for Air Quality Control 391-3-1-.02(2)(a)7.

d. Periods of scheduled and/or preventative maintenance of control technology equipment if such maintenance cannot reasonably be performed during a scheduled outage of the respective EGU.

e. Periods of malfunction of EGU and/or control technology equipment provided that such periods are consistent with the requirements of Paragraph 391-3-1-.02(2)(a)7.

f. Periods when the owner/operator is required to conduct the Relative Accuracy Test Audit and any other necessary periodic quality assurance procedures on the Continuous Emissions Monitoring System located on the bypass stack pursuant to 40 CFR Part 75 or the Georgia Department of Natural Resources ***Procedures for Testing and Monitoring Sources of Air Pollutants.***

g. Periods when the owner/operator is required to conduct any performance tests on the bypass stack as required by state or federal air quality rules, air quality operating permits, or as ordered by the Division.

h. Division approved periods of research and development of emission control technologies, provided that the unit does not exceed other applicable emission limits. For purposes of this subparagraph, the owner/operator shall submit a request for approval under this subparagraph at least 120 days prior to such date as well as including the following items: (1) length of time of research and development (R&D) period; (2) identification of steps to take to minimize emissions in accordance with best operational practices during R&D period; (3) for periods of R&D lasting more than 48 hours during any 5-day period, a demonstration that any increase in emissions resulting from the R&D project that are above that which is allowed by this subparagraph (sss) will not cause or significantly contribute to a violation of any national ambient air quality standard or prevent compliance with any other applicable provisions.

i. Any other occasion not covered by subparagraph a. through h., as approved by the Division.

3.4.15 For steam generating unit SG03, except for periods indicated in Condition No. 3.4.19, the Permittee shall not discharge, or cause the discharge, into the atmosphere, any gases which contain SO_2 emissions in excess of 5 percent (0.05) of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.
[391-3-1-.02(2)(uuu)2]

3.4.16 Effective January 1, 2013 for steam generating unit SG04, except for periods indicated in Condition No. 3.4.19, the Permittee shall not discharge, or cause the discharge, into the atmosphere, any gases which contain SO_2 emissions in excess of 5 percent (0.05) of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.
[391-3-1-.02(2)(uuu)2]

3.4.17 Effective January 1, 2014 for steam generating unit SG02, except for periods indicated in Condition No. 3.4.19, the Permittee shall not discharge, or cause the discharge, into the atmosphere, any gases which contain SO_2 emissions in excess of 5 percent (0.05) of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.
[391-3-1-.02(2)(uuu)2]

3.4.18 Effective January 1, 2015 for steam generating unit SG01, except for periods indicated in Condition No. 3.4.19, the Permittee shall not discharge, or cause the discharge, into the atmosphere, any gases which contain SO_2 emissions in excess of 5 percent (0.05) of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.
[391-3-1-.02(2)(uuu)2]

3.4.19 For purposes of this permit, requirements in Conditions 3.4.15, 3.4.16, 3.4.17, and 3.4.18 do not apply during the following periods.
[391-3-1-.02(2)(uuu)4]

a. Restarting an EGU when all Electric Utility Stream Generating Units [as listed in this Condition] at a facility are down and off-site power is not available (also known as a "Black Start").

b. Periods of startup of an Electric Utility Steam Generating Unit provided that such periods are consistent with the requirements outlined in the Georgia Rules for Air Quality Control 391-3-1-.02(2)(a)7.

c. Periods of shutdown of an Electric Utility Steam Generating Unit provided that such periods are consistent with the requirements outlined in the Georgia Rules for Air Quality Control 391-3-1-.02(2)(a)7.

d. Periods of scheduled and/or preventative maintenance of control technology equipment if such maintenance cannot reasonably be performed during a scheduled outage of the respective Electric Utility Steam Generating Unit.

e. Periods of malfunction of an Electric Utility Steam Generating Unit and/or control technology equipment provided that such periods are consistent with the requirements outlined in the Georgia Rules for Air Quality Control 391-3-1-.02(2)(a)7.

f. Periods when the Permittee is required to conduct the Relative Accuracy Test Audit (RATA) and any other necessary periodic quality assurance procedures on the Continuous Emissions Monitoring System (CEMS) located on the bypass stack pursuant to 40 CFR Part 75 or the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants**.

g. Periods when the Permittee is required to conduct any performance testing on the bypass stack as required by State or Federal air quality rules, air quality operating permits or at the request of the Division.

h. Division-approved periods of research and development of emission control technologies provided that the unit does not exceed other applicable emission limits. For purposes of this subparagraph, the owner/operator shall submit a request for approval under this subparagraph at least 120 days prior to such date as well as including the following items: (1) length of time of research and development (R&D) period; (2) identification of steps to take to minimize emissions in accordance with best operational practices during R&D period; (3) for periods of R&D lasting more than 48 hours during any 5-day period, a demonstration that any increase in emissions resulting from the R&D project that are above that which is allowed by this subparagraph (uuu) will not cause or significantly contribute to an violation of any national ambient air quality standard or prevent compliance with any other applicable provisions.

3.5 Equipment Standards Not Covered by a Federal or SIP Rule and Not Instituted as an Emission Cap or Operating Limit

None Applicable.

PART 4.0 REQUIREMENTS FOR TESTING

4.1 General Testing Requirements

4.1.1 The Permittee shall cause to be conducted a performance test at any specified emission unit when so directed by the Environmental Protection Division ("Division"). The test results shall be submitted to the Division within 60 days of the completion of the testing. Any tests shall be performed and conducted using methods and procedures that have been previously specified or approved by the Division.
[391-3-1-.02(6)(b)1(i)]

4.1.2 The Permittee shall provide the Division thirty (30) days (or sixty (60) days for tests required by 40 CFR Part 63) prior written notice of the date of any performance test(s) to afford the Division the opportunity to witness and/or audit the test.
[391-3-1-.02(3)(a) and 40 CFR 63.7(b)(1)]

4.1.3 Performance and compliance tests shall be conducted and data reduced in accordance with applicable procedures and methods specified in the Division's ***Procedures for Testing and Monitoring Sources of Air Pollutants***. The methods for the determination of compliance with emission limits listed under Sections 3.2, 3.3, 3.4 and 3.5 which pertain to the emission units listed in Section 3.1 are as follows:

a. Method 1 for the determination of sample point locations.

b. Method 2 for the determination of stack gas flow rate.

c. Method 3 or 3A for the determination of stack gas molecular weight.

d. Method 3A or 3B for the determination of the emissions rate correction factor or excess air.

e. Method 4 for the determination of stack gas moisture.

f. Method 5 or Method 17, as applicable, for the determination of particulate matter concentration.

g. Method 6 or 6C for the determination of sulfur dioxide concentration.

h. Method 9 and the procedures contained in Section 1.3 of the above referenced document for the determination of opacity,

i. Method 19, when applicable, to convert particulate matter, carbon monoxide, sulfur dioxide, and nitrogen oxide concentrations (i.e., grains/dscf for PM, ppm for gaseous pollutants), as determined using other methods specified in this section, to emission rates (i.e., lb/MMBtu),

j. The procedures contained in Section 2.116.2 of the above-referenced document shall be used for the determination of nitrogen oxides concentration from the steam generating units with emission units ID Nos. SG01, SG02, SG03, and SG04 for purposes of verifying compliance with Georgia Rule 391-3-1-.02(2)(jjj),

k. Method 7E for the determination of nitrogen oxides concentration for the purposes other than verifying compliance with Georgia Rule 391-3-1-.02(2)(jjj),

l. The procedures contained in Section 2.125.4 of the above-referenced document shall be used for the determination of sulfur dioxide emission rates from steam generating units with emission units ID Nos. SG01, SG02, SG03 and SG04 for purposes of verifying compliance with Georgia Rule 391-3-1-.02(2)(uuu).

Minor changes in methodology may be specified or approved by the Director or his designee when necessitated by process variables, changes in facility design, or improvement or corrections that, in his opinion, render those methods or procedures, or portions thereof, more reliable.
[391-3-1-.02(3)(a)]

State Only Enforceable Condition

4.1.4 The Permittee shall provide, with the notification required under Condition 4.1.2, a test plan in accordance with Division guidelines.
[391-3-1-.02(3)(a)]

4.2 Specific Testing Requirements

4.2.1 The Permittee shall conduct the following performance tests on the following emissions units at the frequency specified:

a. Particulate matter tests on Steam Generating Units (Emission Unit ID Nos. SG01, SG02, SG03 and SG04) scrubber bypass stacks (ST01, ST02, ST03, and ST04). The tests shall be conducted for each unit within 30 days following 8760 operating hours of using the bypass stack or 60 months since the previous test of that unit, whichever comes first. Prior to the effective dates of Georgia Rule 391-3-1-.02(2)(uuu) for Units 1, 2, 3, and 4, the Permittee may, if results from the previous tests are fifty percent or less of the limitation in Condition 3.3.2, request that testing be deferred for a period of no greater than 8760 operating hours of the bypass stacks from the required test date. Such request shall be made in written form at least 30 days prior to the scheduled test.
[391-3-1-.02(6)(b)1(i)]

b. Particulate matter tests on Steam Generating Units (Emissions Unit ID Nos. SG01, SG02, SG03 and SG04) scrubber stacks (ST05, ST06, ST07 and ST08). The tests shall be conducted once every 60 calendar months or as requested by the Division.
[391-3-1-.02(6)(b)1(i)]

4.2.2 [Reserved]

4.2.3 The Permittee shall conduct a repeat performance test(s) once every 5 years on the materials handling system (Emission Unit ID MHS) to ensure ongoing compliance with the emissions limitations contained in Condition 3.3.7 of this permit. Testing shall be conducted according to the methods and procedures contained in 40 CFR 60.675.
[40 CFR 60.8, 40 CFR 60 Subpart OOO]

4.2.4 The Permittee shall conduct the following performance test(s) on the following emissions units at the frequency specified:

a. Initial and subsequent performance tests for sulfur dioxide emissions on Steam Generating Units 1, 2, 3, and 4 (Emission Unit IDs SG01, SG02, SG03 and SG04), as specified below.

The initial performance test is based upon the 95 percent reduction required by Conditions 3.4.15, 3.4.16, 3.4.17, and 3.4.18 for the first 30 successive boiler operating days following January 1, 2013 for steam generating unit SG04, January 1, 2014 for steam generating unit SG02, and January 1, 2015 for steam generating unit SG01. The initial performance tests are to be scheduled so that the first day of the 30 consecutive operating days is completed upon the first boiler operating day on or after the applicable effective dates. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-day percent reduction for Sulfur Dioxide (SO_2) is calculated to show compliance with Conditions 3.4.15, 3.4.16, 3.4.17, and 3.4.18. Compliance with applicable percent reduction requirements is determined based on the average inlet and outlet SO_2 emissions rates for the 30 successive boiler operating days. If the Permittee has not obtained the minimum quantity of emission data as required under Section 2.125.3(d) of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants**, compliance of the affected facility with the emission requirements required by Conditions 3.4.15, 3.4.16, 3.4.17, and 3.4.18 for the day on which the 30-day period ends may be determined by the Director by following the applicable procedures in Section 12.7 of Method 19 of Appendix A of the **Procedures for Testing and Monitoring Sources of Air Pollutants**.
[391-3-1-.02(6)(b)1(i) and PTM Section 2.125]

PART 5.0 REQUIREMENTS FOR MONITORING (Related to Data Collection)

5.1 General Monitoring Requirements

5.1.1 Any continuous monitoring system required by the Division and installed by the Permittee shall be in continuous operation and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Monitoring system response, relating only to calibration checks and zero and span adjustments, shall be measured and recorded during such periods. Maintenance or repair shall be conducted in the most expedient manner to minimize the period during which the system is out of service.
[391-3-1-.02(6)(b)1]

5.2 Specific Monitoring Requirements

5.2.1 The Permittee shall install, calibrate, maintain, and operate a system to continuously monitor and record the indicated pollutants on the following equipment. Each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. A Continuous Opacity Monitoring System (i.e. four COMS) one each located in each liner of the scrubber bypass stacks (ST01, ST02, ST03, and ST04).

b. A Continuous Opacity Monitoring System (i.e. four COMS) located upstream (i.e. near the inlet) to each scrubber (FGD1, FGD2, FGD3 and FGD4).

c. A Continuous Emissions Monitoring System (i.e. four CEMS), for the measurement of nitrogen oxides concentration (ppm) and diluent concentrations (either Oxygen or Carbon Dioxide, percent), located in each liner of the scrubber bypass stacks (ST01, ST02, ST03, and ST04).

d. A Continuous Emissions Monitoring System (i.e. four CEMS), for the measurement of nitrogen oxides concentration (ppm) and diluent concentrations (either Oxygen or Carbon Dioxide, percent), to be located in each liner of the scrubber stacks (ST05, ST06, ST07, and ST08).

e. The output of the CEMS described in Paragraphs 5.2.1.c and d above will also be displayed and recorded in terms of pounds per million British thermal units (lb/million Btu).

f. A Continuous Emissions Monitoring System (CEMS), for the measurement of sulfur dioxide concentration (ppm) and diluent concentrations (either Oxygen or Carbon Dioxide, percent), on Steam Generating Units 1, 2, 3 and 4 (Emission Unit IDs SG01, SG02, SG03 and SG04). Sulfur dioxide emissions are monitored in each liner of the bypass stack (ST01, ST02, ST03, and ST04), and in each liner of the scrubber stack (ST05, ST06, ST07, and ST08). For Unit 3, and effective January 1, 2013 for Unit 4, January 1, 2014 for Unit 2, and January 1, 2015 for Unit 1, sulfur dioxide emissions must be monitored at both the inlet, and outlet of the SO_2 control device. The output of the CEMS shall be expressed in terms of pounds per million British thermal units (lb/MMBtu).

g. On and after the sixtieth day after achieving the maximum production rate at a scrubber (FGD3 or FGD4), but not later than 180 days after initial startup, a Continuous Monitoring System (CMS) for the measurement of the number of FGD recycle pumps running (Control Device IDs FGD3 and FGD4) for Steam Generating Units 3 and 4 (Emission Unit ID Nos. SG03 and SG04).

5.2.2 [Reserved]

State Only Enforceable Condition.

5.2.3 The Permittee shall, upon written request by the Division, analyze any used oil to be burned in Steam Generating Units 1, 2, 3, and 4 (Emission Unit IDs SG01, SG02, SG03, and SG04). The sample(s) shall be obtained and analyzed using the following methods:
[391-3-1-.02(6)(b)1(i)]

a. The procedures described in U.S. Environmental Protection Agency document EPA-600/2-80-018 (Samplers and Sampling Procedures for Hazardous Waste Streams) shall be used to obtain the sample.

b. Method 6010B, contained in the SW-846 methods manual of U.S. Environmental Protection Agency's Office of Solid Waste, shall be used to determine concentrations of arsenic, cadmium, chromium, and lead.

c. SW-846 Method 9077C shall be used to determine total halogens.

d. ASTM D93 shall be used to determine flash point.

e. Polychlorinated Biphenyls (PCB) shall be determined using the test method described in U.S. Environmental Protection Agency Document EPA-600/4-81-045 (*The Determination of Polychlorinated Biphenyls in Transformer Fluid and Waste Oil*).

5.2.4 The Permittee shall monitor sulfur dioxide emissions from Steam Generating Units SG01, SG02, SG03, and SG04 using the SO_2 CEMS as required by Condition 5.2.1f. A 3-hour rolling average SO_2 emission rate in pounds per million BTU shall be calculated.
[40 CFR 60.45(b)(2) and 40 CFR 70.6(a)(3)(i)]

5.2.5 The following pollutant specific emission unit(s) (PSEU) is/are subject to the Compliance Assurance Monitoring (CAM) Rule in 40 CFR 64.

Emission Unit	Pollutant
Steam Generating Unit 1 (SG01)	Particulate Matter
Steam Generating Unit 2 (SG02)	Particulate Matter
Steam Generating Unit 3 (SG03)	Particulate Matter
Steam Generating Unit 4 (SG04)	Particulate Matter

Permit conditions in this permit for the PSEU(s) listed above with regulatory citation 40 CFR 70.6(a)(3)(i) are included for the purpose of complying with 40 CFR 64. In addition, the Permittee shall meet the requirements, as applicable, of 40 CFR 64.7, 64.8, and 64.9.
[40 CFR 64]

5.2.6 The Permittee shall comply with the performance criteria listed in the table below for the particulate matter emissions from steam generating unit SG01.
[40 CFR 64.6(c)(1)(iii)]

Performance Criteria [64.4(a)(3)]	Indicator No. 1 Opacity from SG01 exhaust
A. Data Representativeness [64.3(b)(1)]	The continuous opacity monitoring system (COMS) is located in the SG01 exhaust. The COMS was installed at a representative location in the stack per 40 CFR 60, Appendix B, PS-1.
B. Verification of Operational Status (new/modified monitoring equipment only) [64.3(b)(2)]	Not applicable.
C. QA/QC Practices and Criteria [64.3(b)(3)]	The COMS was initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
D. Monitoring Frequency [64.3(b)(4)]	The opacity is monitored continuously.
E. Data Collection Procedures [64.3(b)(4)]	The data acquisition system (DAS) retains all 6-minute opacity data.
F. Averaging Period [64.3(b)(4)]	The 6-minute opacity data is used to calculate 3-hour block averages.

5.2.7 The Permittee shall comply with the performance criteria listed in the table below for the particulate matter emissions from steam generating unit SG02.
[40 CFR 64.6(c)(1)(iii)]

Performance Criteria [64.4(a)(3)]	**Indicator No. 1 Opacity from SG02 exhaust**
G. Data Representativeness [64.3(b)(1)]	The continuous opacity monitoring system (COMS) is located in the SG02 exhaust. The COMS was installed at a representative location in the stack per 40 CFR 60, Appendix B, PS-1.
H. Verification of Operational Status (new/modified monitoring equipment only) [64.3(b)(2)]	Not applicable.
I. QA/QC Practices and Criteria [64.3(b)(3)]	The COMS was initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed.
J. Monitoring Frequency [64.3(b)(4)]	The opacity is monitored continuously.
K. Data Collection Procedures [64.3(b)(4)]	The data acquisition system (DAS) retains all 6-minute opacity data.
L. Averaging Period [64.3(b)(4)]	The 6-minute opacity data is used to calculate 3-hour block averages.

5.2.8 The Permittee shall comply with the performance criteria listed in the table below for the particulate matter emissions from steam generating unit SG03.
[40 CFR 64.6(c)(1)(iii)]

Performance Criteria [64.4(a)(3)]	Indicator No. 1 Opacity from FGD3 Inlet	Indicator No. 2 Number of recycle pumps running in FGD3 for SG03
M. Data Representativeness [64.3(b)(1)]	Opacity is an indicator of particulate matter collection and equipment performance of the ESP and baghouse.	The number of FGD pumps running is an indicator of particulate matter collection and equipment performance of the FGD.
N. Verification of Operational Status (new/modified monitoring equipment only) [64.3(b)(2)]	Not applicable.	Not applicable.
O. QA/QC Practices and Criteria [64.3(b)(3)]	The COMS was initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed. The opacity monitors are calibrated as per manufacturer's recommendations.	The FGD controls are calibrated per manufacturer's recommendations.
P. Monitoring Frequency [64.3(b)(4)]	The opacity is monitored continuously.	The number of FGD recycle pumps running is monitored continuously.
Q. Data Collection Procedures [64.3(b)(4)]	The data acquisition system (DAS) retains all 3-hour average opacity data.	The DAS retains all 3-hour average FGD number of recycle pumps running data.
R. Averaging Period [64.3(b)(4)]	The 10-second opacity data is used to calculate 3-hour block averages.	The 1-minute data is used to calculate 3-hour block averages.

5.2.9 The Permittee shall comply with the performance criteria listed in the table below for the particulate matter emissions from steam generating unit SG04.
[40 CFR 64.6(c)(1)(iii)]

Performance Criteria [64.4(a)(3)]	**Indicator No. 1 Opacity from FGD4 Inlet**	**Indicator No. 2 Number of recycle pumps running in FGD4 for SG04**
S. Data Representativeness [64.3(b)(1)]	Opacity is an indicator of particulate matter collection and equipment performance of the ESP and baghouse.	The number of FGD pumps running is an indicator of particulate matter collection and equipment performance of the FGD.
T. Verification of Operational Status (new/modified monitoring equipment only) [64.3(b)(2)]	Not applicable.	Not applicable.
U. QA/QC Practices and Criteria [64.3(b)(3)]	The COMS was initially installed and evaluated per PS-1. Zero and span drift are checked daily and a quarterly filter audit is performed. The opacity monitors are calibrated as per manufacturer's recommendations.	The FGD controls are calibrated per manufacturer's recommendations.
V. Monitoring Frequency [64.3(b)(4)]	The opacity is monitored continuously.	The number of FGD recycle pumps running is monitored continuously.
W. Data Collection Procedures [64.3(b)(4)]	The data acquisition system (DAS) retains all 3-hour average opacity data.	The DAS retains all 3-hour average FGD number of recycle pumps running data.
X. Averaging Period [64.3(b)(4)]	The 10-second opacity data is used to calculate 3-hour block averages.	The 1-minute data is used to calculate 3-hour block averages.

5.2.10 The Permittee shall, at all times, maintain the monitoring required by Conditions 5.2.6, 5.2.7, 5.2.8, and 5.2.9, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.
[40 CFR 64.7(b)]

5.2.11 Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of CAM, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The Permittee shall use all the data collected during all other periods in assessing the operation of the control device and associated control sys tem. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.
[40 CFR 64.7(c)]

5.2.12 Upon detecting an excursion or exceedance as defined in Condition 6.1.7b and c, the Permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable. Determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.
[40 CFR 64.7(d)(1) and (2)]

5.2.13 If the Permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring in Conditions 5.2.6, 5.2.7, 5.2.8, and 5.2.9 did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the Permittee shall promptly notify the permitting authority and, if necessary, submit a proposed modification to the part 70 or 71 permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.
[40 CFR 64.7(e)]

5.2.14 The Permittee shall install, calibrate, maintain, and operate monitoring devices for the measurement of the indicated parameters on the following equipment. Where such performance specification(s) exist, each system shall meet the applicable performance specification(s) of the Division's monitoring requirements. Data shall be recorded at the frequency specified below.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Pressure drop for baghouses (APCD IDs BH01, BH02, BH03, and BH04) installed on steam generating units (Emission Unit IDs SG01, SG02, SG03, and SG04). The pressure drop shall be monitored and data recorded as specified in Conditions 5.2.15.

5.2.15 The Permittee shall develop and implement a Preventive Maintenance Program for the baghouses specified in condition 5.2.14 to assure that the provisions of condition 8.17.1 are met. The program shall be subject to review and, if necessary to assure compliance, modification by the Division and shall include the pressure drop ranges that indicate proper operation for each bag house. At a minimum, the following operation and maintenance checks shall be made on at least a weekly basis, and a record of the findings and corrective actions taken shall be kept in a maintenance log:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Record the pressure drop across each baghouse and ensure that it is within the appropriate range.

b. For baghouses equipped with compressed air cleaning systems, check the system for proper operation. This may include checking for low pressure, leaks, proper lubrication, and proper operation of timer and valves.

c. For baghouses equipped with reverse air cleaning systems, check the system for proper operation. This may include checking damper, bypass, and isolation valves for proper operation.

d. For baghouses equipped with shaker cleaning systems, check the system for proper operation. This may include checking shaker mechanism for loose or worn bearings, drive components, mounting; proper operation of outlet/isolation valves; proper lubrication.

e. Check dust collector hoppers and conveying systems for proper operation.

5.2.16 The Permittee shall install continuous temperature monitors on the inlet of baghouses (APCD IDs BH01, BH02, BH03, and BH04) that receive gases from steam generating units (Emission Unit IDs SG01, SG02, SG03, and SG04) and record the time and date of each incident when the temperature exceeds the filter bag design temperature. The Permittee shall record the filter bag design temperature for each baghouse listed. Such records and any supporting calculations shall be made available for inspection.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

5.2.17 Once each day or portion of each day of operation, the Permittee shall inspect all affected emission units as identified in Condition 3.3.7 in the Material Handling System by conducting a walk-through of the facility and noting the occurrence of the following (a check list or other similar log may be used for this purpose.)
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Any emissions unit which exhibits any visible emissions.

b. Any emissions unit that exhibits obvious mechanical failure or malfunction and results in increased air emissions.

For each unit noted with visible emissions, mechanical problems, or malfunctions, the Permittee shall take corrective action with twelve (12) hours and re-inspect the unit when it is operated next to verify that no visible emissions exist and that any mechanical problems or malfunctions have been corrected. The Permittee shall maintain a log of all corrective actions taken, including the dates and times of corrective actions taken and re-inspections.

5.2.18 Within 180 days of startup of the scrubbers FGD1 and FGD2 the Permittee shall conduct testing to determine compliance indicators(s) and submit an updated Compliance Assurance Monitoring (CAM) Plan for the control of particulate emissions from Steam Generating Units 1 and 2 (Emission Unit IDs SG01 and SG02) to the scrubber stack liners (ST05 and ST06).
[40 CFR 64.4(e)]

State-Only Enforceable Condition.

5.2.19 The Permittee shall install, calibrate, maintain, and operate monitoring devices to continuously monitor and record the measurement of the indicated parameters on the following equipment. Where such performance specifications exist, each system shall meet the applicable performance specifications of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. The electrical output of each steam generating unit, SG01, SG02, SG03, and SG04 in megawatts (MW).

b. The Activated Carbon Injection (ACI) rate in pounds per hour of each steam generating unit, SG01, SG02, SG03 and SG04.

State-Only Enforceable Condition.

5.2.20 Using the data required in Conditions 5.2.19a and 5.2.19b, the Permittee shall calculate the minimum Activated Carbon Injection (ACI_m) rates required for SG01, SG02, SG03, and SG04 using the following equation:

$$ACI_m \text{ rate (lb/hr)} = 0.0952 * MW + 16.2$$

The value of ACI_m shall be compared to the actual ACI rates for each applicable steam generating unit for each operating minute as required in Condition 5.2.19b. For each hour or portion of each hour of operation, a positive signal will be recorded if the ACI rates for each steam generating unit (Emission Unit IDs SG01, SG02, SG03, and SG04) are greater than or equal to the calculated minimum ACI_m for at least 30 minutes each hour.

5.2.21 The CEMS required by Condition 5.2.1f shall be operated and data recorded during all periods of operation of the affected steam generating units with emission unit IDs SG01, SG02, SG03 and SG04 including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments and any period allowed under Condition 3.4.19.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

5.2.22 The Permittee shall obtain SO_2 emission data for at least 75 percent of all operating hours for each 30 successive boiler operating days. The 1-hour averages required under Section 1.4(h) of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants** are expressed in ng/J (lb/MMBTU) heat input and used to calculate the average emission rates under Georgia Rule 391-3-1-.02(2)(uuu). The 1-hour averages are calculated using the data points required under Section 1.4(h)(2) of the referenced document. If the minimum data requirement of this condition is not met, the Permittee may use the procedures of Section 2.125.3(f) of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants** to supplement the data collected.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

5.2.23 The Permittee is required to prepare and submit to the Division for approval a unit specific monitoring plan as required by Section 2.125.3(i) of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants** for the SO_2 CEMS required by Condition 5.2.1f, at least 45 days before commencing certification testing of the monitoring system. The Permittee shall comply with the requirements in the plan. The plan must address the following information:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (e.g., on or downstream of the last control device).

b. Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

c. Performance evaluation procedures and acceptance criteria. (e.g., calibrations, relative accuracy test audits (RATA), etc.)

d. Operation and maintenance procedures in accordance with the general requirements of 40 CFR Part 75 or other acceptable procedures approved by the Division.

e. Ongoing recordkeeping and reporting procedures.

5.2.24 The SO_2, CO_2, and O_2 CEMS required by Condition 5.2.1 shall be installed, certified, and operated in accordance with the applicable procedures in Performance Specification 2 or 3 in Appendix B of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants** or in accordance with the procedures in Appendices A and B to 40 CFR Part 75. Daily calibration drift assessments and quarterly accuracy determinations shall be done in accordance with Procedure 1 in Appendix F of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants**. A data assessment report (DAR) shall be prepared according to Section 7 of Procedure 1 in Appendix F and shall be maintained on site and available for inspection or submittal to the Director. The Permittee may elect to implement alternative data accuracy procedures in Section 2.125.3(j) of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants**.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

PART 6.0 RECORD KEEPING AND REPORTING REQUIREMENTS

6.1 General Record Keeping and Reporting Requirements

6.1.1 Unless otherwise specified, all records required to be maintained by this Permit shall be recorded in a permanent form suitable for inspection and submission to the Division and to the EPA. The records shall be retained for at least five (5) years following the date of entry.
[391-3-1-.02(6)(b)1(i) and 40 CFR 70.6(a)(3)]

6.1.2 In addition to any other reporting requirements of this Permit, the Permittee shall report to the Division in writing, within seven (7) days, any deviations from applicable requirements associated with any malfunction or breakdown of process, fuel burning, or emissions control equipment for a period of four hours or more which results in excessive emissions.

The Permittee shall submit a written report that shall contain the probable cause of the deviation(s), duration of the deviation(s), and any corrective actions or preventive measures taken.
[391-3-1-.02(6)(b)1(iv), 391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(3)(iii)(B)]

6.1.3 The Permittee shall submit written reports of any failure to meet an applicable emission limitation or standard contained in this permit and/or any failure to comply with or complete a work practice standard or requirement contained in this permit which are not otherwise reported in accordance with Conditions 6.1.4 or 6.1.2. Such failures shall be determined through observation, data from any monitoring protocol, or by any other monitoring which is required by this permit. The reports shall cover each semiannual period ending June 30 and December 31 of each year, shall be postmarked by August 29, and February 28, respectively following each reporting period, and shall contain the probable cause of the failure(s), duration of the failure(s), and any corrective actions or preventive measures taken.
[391-3-1-.03(10)(d)1.(i) and 40 CFR 70.6(a)(3)(iii)(B)]

6.1.4 The Permittee shall submit a written report containing any excess emissions, exceedances, and/or excursions as described in this permit and any monitor malfunctions for each quarterly period ending March 31, June 30, September 30, and December 31 of each year. All reports shall be postmarked by May 30, August 29, November 29, and February 28, respectively following each reporting period. In the event that there have not been any excess emissions, exceedances, excursions or malfunctions during a reporting period, the report should so state. Otherwise, the contents of each report shall be as specified by the Division's ***Procedures for Testing and Monitoring Sources of Air Pollutants*** and shall contain the following:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(iii)(A)]

a. A summary report of excess emissions, exceedances and excursions, and monitor downtime, in accordance with Section 1.5(c) and (d) of the above referenced document, including any failure to follow required work practice procedures.

b. Total process operating time during each reporting period.

c. The magnitude of all excess emissions, exceedances and excursions computed in accordance with the applicable definitions as determined by the Director, and any conversion factors used, and the date and time of the commencement and completion of each time period of occurrence.

d. Specific identification of each period of such excess emissions, exceedances, and excursions that occur during startups, shutdowns, or malfunctions of the affected facility. Include the nature and cause of any malfunction (if known), the corrective action taken or preventive measures adopted.

e. The date and time identifying each period during which any required monitoring system or device was inoperative (including periods of malfunction) except for zero and span checks, and the nature of the repairs, adjustments, or replacement. When the monitoring system or device has not been inoperative, repaired, or adjusted, such information shall be stated in the report.

f. Certification by a Responsible Official that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.

6.1.5 Where applicable, the Permittee shall keep the following records:
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(3)(ii)(A)]

a. The date, place, and time of sampling or measurement;

b. The date(s) analyses were performed;

c. The company or entity that performed the analyses;

d. The analytical techniques or methods used;

e. The results of such analyses; and

f. The operating conditions as existing at the time of sampling or measurement.

6.1.6 The Permittee shall maintain files of all required measurements, including continuous monitoring systems, monitoring devices, and performance testing measurements; all continuous monitoring system or monitoring device calibration checks; and adjustments and maintenance performed on these systems or devices. These files shall be kept in a permanent form suitable for inspection and shall be maintained for a period of at least five (5) years following the date of such measurements, reports, maintenance and records.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6 (a)(3)(ii)(B)]

6.1.7 For the purpose of reporting excess emissions, exceedances or excursions in the report required in Condition 6.1.4, the following excess emissions, exceedances, and excursions shall be reported:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Excess emissions: (means for the purpose of this Condition and Condition 6.1.4, any condition that is detected by monitoring or record keeping which is specifically defined or stated to be, excess emissions by an applicable requirement)

i. Excess emissions of nitrogen oxides as described in Condition 6.2.10a.

ii. Excess emissions of nitrogen oxides as described in Condition 6.2.10b.

iii. Any six-minute average opacity, as recorded by the COMS for any steam generating unit (Emission Unit IDs SG01, SG02, SG03, and SG04) that exceeds 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

iv. Any 3-hour average nitrogen oxide emissions rate, as measured by the CEMS installed on steam generating units (Emission Unit IDs SG01, SG02, SG03, and SG04) that exceeds 0.7 lb/MMBtu heat input.

v. Any 3-hour average sulfur dioxide emission rate, as measured by the CEMS installed on steam generating units (Emission Unit IDs SG01, SG02, SG03, and SG04), that exceeds 1.2 lb/MMBtu heat input.

b. Exceedances: (means for the purpose of this Condition and Condition 6.1.4, any condition that is detected by monitoring or record keeping that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) do not meet the applicable emission limitation or standard consistent with the averaging period specified for averaging the results of the monitoring)

i. Any time fuel fired in any start-up boiler (Emission Unit IDs SB01 or SB02) has a sulfur content which exceeds 3.0 percent sulfur, by weight.

ii. An ozone season (May 01 through September 30) total NO_X emission rate which exceeds 32,335.8 tons from the applicable equipment specified in Condition 3.2.6.

iii. Any 30 day rolling average SO_2 percent reduction that is calculated in accordance with the procedures of Condition 6.2.14 that is less than 95% for SG01, SG02, SG03, and SG04. This condition is effective for SG03 and should become effective January 1, 2013 for SG04, January 1, 2014 for SG02, and January 1, 2015 for SG01.

c. Excursions: (means for the purpose of this Condition and Condition 6.1.4, any departure from an indicator range or value established for monitoring consistent with any averaging period specified for averaging the results of the monitoring)

i. For Source 1 (Emission Unit ID SG01), any three-hour block average during which the arithmetic average opacity, as measured by the COMS, exceeds 20 percent. A three-hour block average shall be defined as any one of the eight consecutive three-hour time periods between 12:00 midnight and the following midnight.

ii. For Source 2 (Emission Unit ID SG02), any three-hour block average during which the arithmetic average opacity, as measured by the COMS, exceeds 20 percent. A three-hour block average shall be defined as any one of the eight consecutive three-hour time periods between 12:00 midnight and the following midnight.

iii. For Source 3 (Emission Unit ID SG03), any three-hour block average during which the arithmetic average opacity, as measured by the COMS, exceeds 20 percent and less than four FGD recycle pumps are running. A three-hour block average shall be defined as any one of the eight consecutive three-hour time periods between 12:00 midnight and the following midnight.

iv. For Source 4 (Emission Unit ID SG04), any three-hour block average during which the arithmetic average opacity, as measured by the COMS, exceeds 20 percent and less than four FGD recycle pumps are running. A three-hour block average shall be defined as any one of the eight consecutive three-hour time periods between 12:00 midnight and the following midnight.

v. Any time coal derived synthetic fuel fired in any steam generating unit (Emission Unit IDs SG01, SG02, SG03, or SG04) does not meet the specification of Condition 3.2.1e.

vi. Each occurrence when the temperature at the inlet of any baghouse specified in Condition 5.2.16 exceeds the filter bag design temperature recorded in accordance with Condition 5.2.16.

vii. Any instance a weekly preventative maintenance check required by Condition 5.2.15 reveals a problem that is not resolved according to the Preventive Maintenance Program.

viii. For sources specified in Condition 5.2.17, any required daily inspection during which any emissions unit which exhibits any visible emissions that is not corrected within 12 hours of the observation.

State-Only Enforceable Condition.

ix. Any 30 consecutive operating day period in which actual ACI rate recorded by condition 5.2.19b is less than the minimum ACI rate determined in condition 5.2.20 for 10% or more of the operating hours during that period, excluding periods described in Georgia Rules for Air Quality Control 391-3-1-.02(2)(sss)17.

6.2 Specific Record Keeping and Reporting Requirements

State Only Enforceable Condition.

6.2.1 The Permittee shall retain monthly records of all fuel burned (except c, d and f below which shall be monitored on an as received basis), in the steam generating units with Emission Unit IDs SG01, SG02, SG03, and SG04, for five years after the date and year of record. The records shall be available for inspection or submittal to the Division, upon request, and contain the following:
[391-3-1-.02(6)(b)1(i)]

a. Quantity (tons) of coal burned.

b. Aggregate total quantity (gallons) of distillate oil, No. 2 fuel oil, biodiesel, biodiesel blends, or very low sulfur oil burned.

c. Quantity (tons) of sawdust received.

d. Quantity (tons) of biomass received.

e. Quantity (gallons) of used oil burned.

f. Quantity (tons) of coal-derived synthetic fuel received.

State Only Enforceable Condition.

6.2.2 The Permittee shall maintain records of representative samples of the coal and sawdust burned in the steam generating units (Emission Unit IDs SG01, SG02, SG03, and SG04) for five years after the date and year of record. The records shall be available for inspection or submittal to the Division, upon request, and contain the following:
[391-3-1-.02(6)(b)1(i)]

a. Percent ash content of coal.

b. Heat content (Btu per pound) of sawdust.

6.2.3 For each shipment of fuel oil received, the Permittee shall obtain from the supplier of the fuel oil, a statement certifying that the oil complies with the specifications of fuel oil contained in ASTM D396, ASTM D975, or ASTM D6751. As an alternative to the procedure described above, the Permittee may, for each shipment of fuel oil received, obtain a sample for analysis of the sulfur content. The procedures of ASTM D4057 shall be used to acquire the sample. Sulfur content shall be determined using the procedures of Test Method ASTM D129, D1552, or by some other test method approved by the US EPA and acceptable to the Division.
[391-3-1-.02(6)(b)1(i) and 40 CFR 70.6(a)(3)(i)]

6.2.4 The Permittee shall obtain from the supplier a statement certifying that each shipment of coal derived synthetic fuel to be received complies with the specifications as described in Condition 3.2.1e.
[391-3-1-.02(6)(b)1(i)]

6.2.5 For each trainload of coal that is unloaded at the facility, the Permittee shall observe the unloading process to ensure that the dust suppression system for the coal handling system (Emission Unit ID CHS) is working properly and that all spray nozzles are operating with adequate water pressure and flow for effective dust control. The Permittee shall record the date and time that any corrective measures were taken to ensure that the dust suppression system is working properly and shall describe the measures taken.
[40 CFR 60.254(c) and 40 CFR 70.6(a)(3)(i)]

6.2.6 The Permittee shall maintain a record of all actions taken in accordance with Condition 3.4.4b to suppress fugitive dust from the ash handling system (Emission Unit ID AHS). Such records shall include the date and time of occurrence and a description of the actions taken.
[391-3-1-.02(6)(b)(1)(i) and 40 CFR 70.6(a)(3)(i)]

Record Keeping Requirements for the Ozone Season NO_X Emission Caps

6.2.7 The Permittee shall use the data obtained from the NO_X CEMS to compute the monthly mass emission rate, in tons per calendar month, of NO_X from the following coal-fired steam generating units on a combined basis: Emission Unit IDs SG01, SG02, SG03, and SG04 at Plant Bowen (AFS No. 015-00011); Emission Unit IDs SG01, SG02, SG03, and SG04 at Plant Branch (AFS No. 237-00008); Emission Unit IDS SG01, SG02, SG03, and SG04 at Plant Hammond (AFS No. 115-00003); Emission Unit IDS SGM1 and SGM2 at Plant McDonough (AFS No. 067-00003); Emission Unit IDs SG01, SG02, SG03, SG04 at Plant Scherer (AFS No. 207-00008); Emission Unit IDS SG01 and SG02 at Plant Wansley (AFS No. 149-00001); Emission Unit IDs SG01, SG02, SG03, SG04, SG05, SG06, and SG07 at Plant Yates (AFS No. 077-00001). This emission rate must include emissions from startup, shutdown, and malfunction. This condition only applies during the ozone season (May 01 to September 30).
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

6.2.8 The Permittee shall use the records required by Condition 6.2.7 to determine the ozone season total emission rate, in tons, of NO_X from the following coal-fired steam generating units on a combined basis: Emission Unit IDs SG01, SG02, SG03, and SG04 at Plant Bowen (AFS No. 015-00011); Emission Unit IDs SG01, SG02, SG03, and SG04 at Plant Branch (AFS No. 237-00008); Emission Unit IDs SG01, SG02, SG03, and SG04 at Plant Hammond (AFS No. 115-00003); Emission Unit IDs SGM1 and SGM2 at Plant McDonough (AFS No. 067-00003); Emission Unit IDs SG01, SG02, SG03, SG04 at Plant Scherer (AFS No. 207-00008); Emission Unit IDs SG01 and SG02 at Plant Wansley (AFS No. 149-00001); Emission Unit IDs SG01, SG02, SG03, SG04, SG05, SG06, and SG07 at Plant Yates (AFS No. 077-00001). This emission rate must include emissions from startup, shutdown, and malfunction.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

Record Keeping for the Verification of Georgia Rule (jjj) NO_X Emission Limits

6.2.9 The Permittee shall determine compliance with the NO_X emissions limitations in Condition Nos. 3.4.6 through 3.4.10 using emissions data acquired by the NO_X CEMS. The 30-day rolling average shall be determined as follows:
[391-3-1-.02(6)(b)1(i) and 40 CFR 70.6(a)(3)(i)]

a. The first 30-day averaging period shall begin on the first operating day of the ozone season.

b. The 30-day average shall be the average of all valid hours of NO_X emissions data for any 30 successive operating days during the period of the ozone season.

c. The last 30-day averaging period shall end on the last operating day of the ozone season.

d. After the first 30-day average, a new 30-day rolling average shall be calculated after each operating day.

e. For the purpose of this Permit, an operating day is a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time. It is not necessary for the fuel to be combusted continuously for the entire 24-hour period.

6.2.10 The Permittee shall determine compliance with the limitation using the procedures of Section 2.116.2 of the Division's ***Procedures for Testing and Monitoring Sources of Air Pollutants***. The Permittee shall maintain the records specified in Section 2.116.4 of the aforementioned procedures document and use these records to prepare a quarterly report. Reportable emissions are any calculated 30-day rolling average NO_X emissions rate which exceeds the limit established in Condition Nos. 3.4.6, 3.4.7, 3.4.8, or 3.4.9, whichever is applicable. Excess emissions are those that:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Exceed an area-wide average limit in Condition Nos. 3.4.10 as well as the source's respective Alternative Emission Limitation as specified in Condition Nos. 3.4.6, 3.4.7, 3.4.8, or 3.4.9, whichever is applicable.
b. Exceed the plant-wide average limit in Condition No. 3.4.11 as well as the source's respective Alternative Emission Limitation as specified in Condition Nos. 3.4.6, 3.4.7, 3.4.8, or 3.4.9, whichever is applicable

Reporting Requirements

6.2.11 The Permittee may submit, via electronic media, any report required by Part 6.0 of this permit provided such format has been approved by the Division.
[391-3-1-.02(6)(b)1]

6.2.12 The Permittee shall submit written reports to the Division of reportable emissions under Condition 6.2.10 (excess emissions would be reported per Condition 6.1.7) for each calendar quarter ending June 30 (April excluded) and September 30. All reports shall be postmarked by August 29 and November 29, respectively, following each reporting period. In the event that there have not been any reportable emissions during a reporting period, the report should state as such.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

6.2.13 In accordance with the provisions of 40 CFR 60.7, for any equipment which is subject to the New Source Performance Standard, 40 CFR 60 Subpart OOO, the Permittee shall furnish the Division written notification of the actual date of initial startup of NSPS equipment including equipment description, manufacturer, and serial number if available postmarked within 15 days after such date.
[40 CFR 60 Subpart OOO]

6.2.14 The Permittee shall determine compliance with the SO_2 emissions limitations in Condition No. 3.4.15, 3.4.16, 3.4.17, and 3.4.18 based on the average emission rate for 30 successive boiler operating days.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. The percent of potential SO_2 emissions ($\%P_s$) to the atmosphere shall be computed using the following equation:

$$\%P_s = \frac{(100 - \%R_f)(100 - \%R_g)}{100}$$

Where:
$\%P_s$ = Percent of potential SO_2 emissions, percent;
$\%R_f$ = Percent reduction from fuel pretreatment, percent; and
$\%R_g$ = Percent reduction by SO_2 control system, percent.

b. The procedures of Method 19 may be used to determine percent reduction ($\%R_f$) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and fly ash interactions. This determination is optional.

c. The procedures in Method 19 shall be used to determine the percent SO_2 reduction ($\%R_g$) of any SO_2 control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19, may be used if the percent reduction is calculated using the average emission rate from the SO_2 control device and the average SO_2 input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

6.2.15 The Permittee shall determine compliance with the limitation in Conditions 3.4.15, 3.4.16, 3.4.17, and 3.4.18, using the procedures of Section 2.125.4 of the Division's Procedures for Testing and Monitoring Sources of Air Pollutants. The Permittee shall maintain the records specified in Section 2.125.5 of the aforementioned document and the records used to prepare a quarterly report. Reportable emissions are any calculated 30-day rolling average SO_2 emissions reduction which exceeds the limit established in Conditions 3.4.15, 3.4.16, 3.4.17, and 3.4.18. The following information shall be maintained for each 24-hour reporting period:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Calendar date.

b. Percent reduction of the potential combustion concentration of SO_2 for each 30 successive boiler operating days; reasons for non-compliance with the emissions standards; and description of corrective actions taken.

c. Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 75 percent of the hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

d. Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, or other reasons, and justification for excluding data for reasons other than startup or shutdown conditions.

e. Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

f. Identification of times when hourly averages have been obtained based on manual sampling methods.

g. Identification of the times when the pollutant concentration exceeded full span of the CEMS.

h. Description of any modifications to CEMS which could affect the ability of the CEMS to comply with Performance Specifications 2 or 3.

i. Results of any daily calibration error tests or quarterly accuracy assessment as required under Section 2.125.3(j) of the aforementioned document that does not meet the applicable accuracy specification and the subsequent acceptable daily calibration error test or quarterly accuracy assessment.

6.2.16 The Permittee shall submit written reports to the Division of reportable emissions under Condition 6.2.15 (excess emissions would be reported per Condition 6.1.7) for each calendar quarter. All reports shall be postmarked by May 30, August 29, November 29, and February 28, respectively, following each reporting period. In the event that there have not been any reportable emissions during a reporting period, the report should state as such. The Permittee shall determine compliance with the limitation using the procedures of Section 2.125.4 of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants**. The Permittee shall maintain the records specified in Section 2.125.5 of the aforementioned procedures document and use these records to prepare a quarterly report. Reportable emissions are any calculated 30-day rolling average SO_2 emissions rate which exceeds the limit established in Conditions 3.4.15, 3.4.16, 3.4.17, and 3.4.18, whichever is applicable.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

6.2.17 In the event the minimum quantity of emissions data as required by Section 2.125.4 of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants** is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of Section 2.125.2(d) of the aforementioned document is reported to the Division for that 30-day period.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. The number of hourly averages available for outlet emission rates (n_o) and inlet emission rates (n_i), as applicable.

b. The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i), as applicable.

c. The lower confidence limit for the mean outlet emission rate (E_o*) and the upper confidence limit for the mean inlet emission rate (E_i*), as applicable.

d. The applicable potential combustion concentration.

e. The ratio of the upper confidence limit for the mean outlet emission rate (E_o*) and the allowable emission rate (E_{std}), as applicable.

6.2.18 For any periods for which SO_2 emissions data are not available, the Permittee shall submit a signed statement to the Division indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability. Within the signed statement, the Permittee must include:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Verification of whether the required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

b. The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this text and is representative of plant performance.

c. The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

d. Compliance with the standards has or has not been achieved during the reporting period.

6.2.19 The Permittee shall submit results of each RATA required under Section 2.125.3(j) of the Division's **Procedures of Monitoring and Testing of Air Pollutants** within 60 days of the completion of RATA.
[391-3-1-.03(6)(b)1 and 40 CFR70.6(a)(3)(i)

6.2.20 The Permittee shall document and maintain a record of the following information related to the high pressure steam turbine upgrades for steam generating units SG01, SG02, SG03, and SG04.
[391-3-1-.02(7)(b)15.(i)(I)]

a. A description of the project;

b. Identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

c. A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under Georgia Rule 391-3-1-.02(7)(a)2.(ii)(II)III of this rule and an explanation for why such amount was excluded, and any netting calculations, if applicable.

The records shall be retained for a period of 15 years following resumption of regular operations after the changes.

6.2.21 The Permittee shall monitor CO and VOC from each steam generating unit (Emission Units SG01, SG02, SG03, and SG04) and calculate and maintain a record of the annual emissions, in tons-per-year on a calendar basis, for a period of ten years following resumption of regular operations after installation of the upgraded high pressure steam turbines, and control equipment for each unit. These records shall be retained for a period of five years past the end of each calendar year.

If the Permittee is required to or elects to exclude emissions associated with startups, shutdowns, and/or malfunctions from estimations of projected actual emissions for PSD applicability purposes as allowed by Georgia Rule 391-3-1-.02(7)(a)2.(ii)(II)II, the Permittee may exclude such emissions from the calculation of annual emissions.
[391-3-1-.02(7)(b)15.(i)(III)]

The Permittee shall calculate the actual increase in emissions due to demand growth, in tons per year on a calendar year basis, for a period 10 years following resumption of regular operations after the changes. These records shall be retained for a period of five years past the end of each calendar year.

6.2.22 The Permittee shall submit a report to the Division within 60 days after the end of each year during which records must be generated under Condition 6.2.21 setting out the unit's annual emissions of CO and VOC, from each steam generating unit (Emission Units SG01, SG02, SG03, SG04) during the calendar year that preceded submission of the report.
[391-3-1-.02(7)(b)15.(i)(V)]

PART 7.0 OTHER SPECIFIC REQUIREMENTS

7.1 Operational Flexibility

7.1.1 The Permittee may make Section 502(b)(10) changes as defined in 40 CFR 70.2 without requiring a Permit revision, if the changes are not modifications under any provisions of Title I of the Federal Act and the changes do not exceed the emissions allowable under the Permit (whether expressed therein as a rate of emissions or in terms of total emissions). For each such change, the Permittee shall provide the Division and the EPA with written notification as required below in advance of the proposed changes and shall obtain any Permits required under Rules 391-3-1-.03(1) and (2). The Permittee and the Division shall attach each such notice to their copy of this Permit.
[391-3-1-.03(10)(b)5 and 40 CFR 70.4(b)(12)(i)]

a. For each such change, the Permittee's written notification and application for a construction Permit shall be submitted well in advance of any critical date (typically at least 3 months in advance of any commencement of construction, Permit issuance date, etc.) involved in the change, but no less than seven (7) days in advance of such change and shall include a brief description of the change within the Permitted facility, the date on which the change is proposed to occur, any change in emissions, and any Permit term or condition that is no longer applicable as a result of the change.

b. The Permit shield described in Condition 8.16.1 shall not apply to any change made pursuant to this condition.

7.2 Off-Permit Changes

7.2.1 The Permittee may make changes that are not addressed or prohibited by this Permit, other than those described in Condition 7.2.2 below, without a Permit revision, provided the following requirements are met:
[391-3-1-.03(10)(b)6 and 40 CFR 70.4(b)(14)]

a. Each such change shall meet all applicable requirements and shall not violate any existing Permit term or condition.

b. The Permittee must provide contemporaneous written notice to the Division and to the EPA of each such change, except for changes that qualify as insignificant under Rule 391-3-1-.03(10)(g). Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change.

c. The change shall not qualify for the Permit shield in Condition 8.16.1.

d. The Permittee shall keep a record describing changes made at the source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the Permit, and the emissions resulting from those changes.

e. The source shall obtain any Permits required under Rules 391-3-1-.03(1) and (2).

7.2.2 The Permittee shall not make, without a Permit revision, any changes that are not addressed or prohibited by this Permit, if such changes are subject to any requirements under Title IV of the Federal Act or are modifications under any provision of Title I of the Federal Act. [Rule 391-3-1-.03(10)(b)7 and 40 CFR 70.4(b)(15)]

7.3 Alternative Requirements
[White Paper #2]

Not Applicable.

7.4 Insignificant Activities
(see Attachment B for the list of Insignificant Activities in existence at the facility at the time of permit issuance)

7.5 Temporary Sources
[391-3-1-.03(10)(d)5 and 40 CFR 70.6(e)]

Not Applicable.

7.6 Short-term Activities
(see Form D5 "Short Term Activities" of the Permit application and White Paper #1)

7.6.1 The Permittee shall maintain records of the duration and frequency of the following Short term Activities:

a. Sand blasting for maintenance purposes in accordance with Georgia Rule 391-3-1-.02(2)(n).

b. Asbestos removal in accordance with Georgia Rule 391-3-1-.02(9)(b)7.

7.7 Compliance Schedule/Progress Reports
[391-3-1-.03(10)(d)3 and 40 CFR 70.6(c)(4)]

None applicable.

7.8 Emissions Trading
[391-3-1-.03(10)(d)1(ii) and 40 CFR 70.6(a)(10)]

Not Applicable.

7.9 Acid Rain Requirements

Facility ORIS code: 6257
Effective: January 1, 2011 through December 31, 2015

7.9.1 Emissions which exceed any allowances that the permittee lawfully holds under Title IV of the 1990 CAAA, or the regulations promulgated thereunder, are expressly prohibited.
[40 CFR 70.6(a)(4)]

7.9.2 Permit revisions are not required for increases in emissions that are authorized by allowances acquired pursuant to the State's Acid Rain Program, provided that such increases do not require a permit revision under any other applicable requirement.
[40 CFR 70.6(a)(4)(i)]

7.9.3 This permit does not place limits on the number of allowances the permittee may hold. However, the permittee may not use allowances as a defense to noncompliance with any other applicable requirement.
[40 CFR 70.6(a)(4)(ii)]

7.9.4 Any allowances held by the permittee shall be accounted for according to the procedures established in regulations promulgated under Title IV of the 1990 CAAA.
[40 CFR 70.6(a)(4)(iii)]

7.9.5 Each affected unit, with the exceptions specified in 40 CFR 72.9(g)(6), operated in accordance with the Acid Rain portion of this permit shall be deemed to be operating in compliance with the Acid Rain Program.
[40 CFR 70.6(f)(3)(iii)]

7.9.6 Where an applicable requirement is more stringent than an applicable requirement of regulations promulgated under Title IV of the 1990 CAAA, both provisions shall be incorporated into the permit and shall be enforceable.
[40 CFR 70.6(a)(1)(ii)]

7.9.7 SO_2 Allowance Allocations and NO_X Requirements for each affected unit. [40 CFR 73 (SO_2) and 40 CFR 76 (NO_X)]

EMISSION UNIT ID	EPA ID		2011	2012	2013	2014	2015
SG01	1	SO_2 Allowances	21121	21121	21121	21121	21121
		NO_x Limit	The standard annual average NO_X limit for a Phase II tangentially fired boiler is 0.40 lb/mmBtu. In lieu of this limit, the Permittee may comply with 40 CFR Part 76 by complying with an approved Phase II NO_X averaging plan as described below.				

Pursuant to 40 CFR 76.11, Georgia EPD approves five NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the years 2011, 2012, 2013, 2014 and 2015. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.50 lb/mmBtu**. In addition, this unit shall not have an annual heat input greater than **71,791,890 mmBtu**.

Under the plan, the actual Btu-weighted annual average NO_X emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NO_X emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit.

In accordance with 40 CFR 72.40(b)(2), approval of the averaging plan shall be final only when the Mississippi Department of Environmental Quality, the Alabama Department of Environmental Management, the Florida Department of Environmental Protection, and the Jefferson County Department of Health (Alabama) have also approved this averaging plan.

In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and requirements covering excess emissions.

EMISSION UNIT ID	EPA ID		2011	2012	2013	2014	2015
SG02	2	SO_2 Allowances	21270	21270	21270	21270	21270
		NO_x Limit	The standard annual average NO_X limit for a Phase II tangentially fired boiler is 0.40 lb/mmBtu. In lieu of this limit, the Permittee may comply with 40 CFR Part 76 by complying with an approved Phase II NO_X averaging plan as described below.				

Pursuant to 40 CFR 76.11, Georgia EPD approves five NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the years 2011, 2012, 2013, 2014, and 2015. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.50 lb/mmBtu**. In addition, this unit shall not have an annual heat input greater than **71,474,044 mmBtu**.

Under the plan, the actual Btu-weighted annual average NO_X emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NO_X emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit.

In accordance with 40 CFR 72.40(b)(2), approval of the averaging plan shall be final only when the Mississippi Department of Environmental Quality, the Alabama Department of Environmental Management, the Florida Department of Environmental Protection, and the Jefferson County Department of Health (Alabama) have also approved this averaging plan.

In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and requirements covering excess emissions.

			2011	2012	2013	2014	2015
EMISSION UNIT ID	EPA ID	SO_2 Allowances	21304	21304	21304	21304	21304
SG03	3	NO_x Limit	The standard annual average NO_X limit for a Phase I tangentially fired boiler is 0.45 lb/mmBtu. In lieu of this limit, the Permittee may comply with 40 CFR Part 76 by complying with an approved Phase II NO_X averaging plan as described below.				

Pursuant to 40 CFR 76.11, Georgia EPD approves five NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the years 2011, 2012, 2013, 2014, and 2015. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.29 lb/mmBtu**. In addition, this unit shall not have an annual heat input less than **53,390,136 mmBtu**.

Under the plan, the actual Btu-weighted annual average NO_X emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NO_X emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit.

In accordance with 40 CFR 72.40(b)(2), approval of the averaging plan shall be final only when the Mississippi Department of Environmental Quality, the Alabama Department of Environmental Management, the Florida Department of Environmental Protection, and the Jefferson County Department of Health (Alabama) have also approved this averaging plan.

In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and requirements covering excess emissions.

			2011	2012	2013	2014	2015
EMISSION UNIT ID	EPA ID	SO_2 Allowances	21280	21280	21280	21280	21280
SG04	4	NO_x Limit	The standard annual average NO_X limit for a Phase II tangentially fired boiler is 0.40 lb/mmBtu. In lieu of this limit, the Permittee may comply with 40 CFR Part 76 by complying with an approved Phase II NO_X averaging plan as described below.				

Pursuant to 40 CFR 76.11, Georgia EPD approves five NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the years 2011, 2012, 2013, 2014, and 2015. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.30 lb/mmBtu**. In addition, this unit shall not have an annual heat input less than **53,390,136 mmBtu**.

Under the plan, the actual Btu-weighted annual average NO_X emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NO_X emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit.

In accordance with 40 CFR 72.40(b)(2), approval of the averaging plan shall be final only when the Mississippi Department of Environmental Quality, the Alabama Department of Environmental Management, the Florida Department of Environmental Protection, and the Jefferson County Department of Health (Alabama) have also approved this averaging plan.

In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and requirements covering excess emissions.

Note: The number of allowances allocated to Phase II affected units by U.S. EPA may change as a result of revisions to 40 CFR Part 73. In addition, the number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitates a revision to the unit SO_2 allowance allocations identified in this permit (See CFR 72.84).

7.9.8 Permit Application: The Phase II Acid Rain Permit Application, Compliance Plan, and NO_X Averaging Plan submitted for this source, as corrected by the State of Georgia, is attached as part of this Permit. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.
[40 CFR 72.50(a)(1)]

7.10 Prevention of Accidental Releases (Section 112(r) of the 1990 CAAA)
[391-3-1-.02(10)]

7.10.1 When and if the requirements of 40 CFR Part 68 become applicable, the Permittee shall comply with all applicable requirements of 40 CFR Part 68, including the following.

a. The Permittee shall submit a Risk Management Plan (RMP) as provided in 40 CFR 68.150 through 68.185. The RMP shall include a registration that reflects all covered processes.

b. For processes eligible for Program 1, as provided in 40 CFR 68.10, the Permittee shall comply with 7.10.1.a. and the following additional requirements:

i. Analyze the worst-case release scenario for the process(es), as provided in 40 CFR 68.25; document that the nearest public receptor is beyond the distance to a toxic or flammable endpoint defined in 40 CFR 68.22(a); and submit in the RMP the worst-case release scenario as provided in 40 CFR 68.165.
ii. Complete the five-year accident history for the process as provided in 40 CFR 68.42 and submit in the RMP as provided in 40 CFR 68.168
iii. Ensure that response actions have been coordinated with local emergency planning and response agencies
iv. Include a certification in the RMP as specified in 40 CFR 68.12(b)(4)

c. For processes subject to Program 2, as provided in 40 CFR 68.10, the Permittee shall comply with 7.10.1.a., 7.10.1.b. and the following additional requirements:

i. Develop and implement a management system as provided in 40 CFR 68.15
ii. Conduct a hazard assessment as provided in 40 CFR 68.20 through 68.42
iii. Implement the Program 2 prevention steps provided in 40 CFR 68.48 through 68.60 or implement the Program 3 prevention steps provided in 40 CFR 68.65 through 68.87
iv. Develop and implement an emergency response program as provided in 40 CFR 68.90 through 68.95
v. Submit as part of the RMP the data on prevention program elements for Program 2 processes as provided in 40 CFR 68.170

d. For processes subject to Program 3, as provided in 40 CFR 68.10, the Permittee shall comply with 7.10.1.a., 7.10.1.b. and the following additional requirements:

i. Develop and implement a management system as provided in 40 CFR 68.15
ii. Conduct a hazard assessment as provided in 40 CFR 68.20 through 68.42
iii. Implement the prevention requirements of 40 CFR 68.65 through 68.87
iv. Develop and implement an emergency response program as provided in 40 CFR 68.90 through 68.95
v. Submit as part of the RMP the data on prevention program elements for Program 3 as provided in 40 CFR 68.175

e. All reports and notification required by 40 CFR Part 68 must be submitted electronically using RMP*eSubmit (information for establishing an account can be found at www.epa.gov/emergencies/content/rmp/rmp_esubmit.htm). Electronic Signature Agreements should be mailed to:

MAIL

Risk Management Program (RMP) Reporting Center
P.O. Box 10162
Fairfax, VA 22038

COURIER & FEDEX

Risk Management Program (RMP) Reporting Center
CGI Federal
12601 Fair Lakes Circle
Fairfax, VA 22033

Compliance with all requirements of this condition, including the registration and submission of the RMP, shall be included as part of the compliance certification submitted in accordance with Condition 8.14.1.

7.11 Stratospheric Ozone Protection Requirements (Title VI of the CAAA of 1990)

7.11.1 If the Permittee performs any of the activities described below or as otherwise defined in 40 CFR Part 82, the Permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F, except as provided for motor vehicle air conditioners (MVACs) in Subpart B:

a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to 40 CFR 82.156.

b. Equipment used during the maintenance, service, repair, or disposal of appliance must comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158.

c. Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 CFR 82.161.

d. Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record keeping requirements pursuant to 40 CFR 82.166.
[Note: “MVAC-like appliance” is defined in 40 CFR 82.152.]

e. Persons owning commercial or industrial process refrigeration equipment must comply with the leak repair requirements pursuant to 40 CFR 82.156.

f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR 82.166.

7.11.2 If the Permittee performs a service on motor (fleet) vehicles and if this service involves an ozone-depleting substance (refrigerant) in the MVAC, the Permittee is subject to all the applicable requirements as specified in 40 CFR Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include air-tight sealed refrigeration systems used for refrigerated cargo, or air conditioning systems on passenger buses using HCFC-22 refrigerant.

7.12 Revocation of Existing Permits and Amendments

The following Air Quality Permits, Amendments, and 502(b)10 are subsumed by this permit and are hereby revoked:

Air Quality Permit and Amendment Number(s)	Dates of Original Permit or Amendment Issuance
4911-207-0008-V-02-0	11/15/2005
4911-207-0008-V-02-1	12/12/2006
4911-207-0008-V-02-2	3/7/2007
4911-207-0008-V-02-3	9/17/2008
4911-207-0008-V-02-4	12/2/2008
4911-207-0008-V-02-5	3/12/2009
4911-207-0008-V-02-6	5/29/2009
4911-207-0008-V-02-7	11/16/2009
4911-207-0008-V-02-8	9/17/2009
4911-207-0008-V-02-A	2/23/2010
4911-207-0008-V-02-B	5/12/2010
4911-207-0008-V-02-C	11/23/2010

7.13 Pollution Prevention

None applicable.

7.14 Specific Conditions

None applicable.

7.15 Clean Air Interstate Rule (CAIR) Requirements

[40 CFR 96, 391-3-1-.02(12), 391-3-1-.02(13)]

7.15.1 Permit Application: The CAIR Permit Application, as corrected by the State of Georgia, is attached as part of this Permit. The owners and operators of these CAIR units as identified in Condition 7.15.2 must comply with the standard requirements and special provisions set forth in the application.
[40 CFR 96.121, 96.122, 96.221, 96.222, 96.321, and 96.322]

7.15.2 The owners and operators of the source shall comply with the Annual NO_X Allowance Allocations in accordance with the CAIR requirements as follows:
[40 CFR 96, 391-3-1-.02(12)]

	Emission Unit IDs.	EPA IDs.		2012	2013
Facility Wide	SG01 SG02 SG03 SG04	1 2 3 4	CAIR Facility Wide Annual NO_X Allowances (tpy)	17377	17377

PART 8.0 GENERAL PROVISIONS

8.1 Terms and References

8.1.1 Terms not otherwise defined in the Permit shall have the meaning assigned to such terms in the referenced regulation.

8.1.2 Where more than one condition in this Permit applies to an emission unit and/or the entire facility, each condition shall apply and the most stringent condition shall take precedence.
[391-3-1-.02(2)(a)2]

8.2 EPA Authorities

8.2.1 Except as identified as "State-only enforceable" requirements in this Permit, all terms and conditions contained herein shall be enforceable by the EPA and citizens under the Clean Air Act, as amended, 42 U.S.C. 7401, et seq.
[40 CFR 70.6(b)(1)]

8.2.2 Nothing in this Permit shall alter or affect the authority of the EPA to obtain information pursuant to 42 U.S.C. 7414, "Inspections, Monitoring, and Entry."
[40 CFR 70.6(f)(3)(iv)]

8.2.3 Nothing in this Permit shall alter or affect the authority of the EPA to impose emergency orders pursuant to 42 U.S.C. 7603, "Emergency Powers."
[40 CFR 70.6(f)(3)(i)]

8.3 Duty to Comply

8.3.1 The Permittee shall comply with all conditions of this operating Permit. Any Permit noncompliance constitutes a violation of the Federal Clean Air Act and the Georgia Air Quality Act and/or State rules and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a Permit renewal application. Any noncompliance with a Permit condition specifically designated as enforceable only by the State constitutes a violation of the Georgia Air Quality Act and/or State rules only and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a Permit renewal application.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(i)]

8.3.2 The Permittee shall not use as a defense in an enforcement action the contention that it would have been necessary to halt or reduce the Permitted activity in order to maintain compliance with the conditions of this Permit.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(ii)]

8.3.3 Nothing in this Permit shall alter or affect the liability of the Permittee for any violation of applicable requirements prior to or at the time of Permit issuance.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(f)(3)(ii)]

8.3.4 Issuance of this Permit does not relieve the Permittee from the responsibility of obtaining any other permits, licenses, or approvals required by the Director or any other federal, state, or local agency.
[391-3-1-.03(10)(e)1(iv) and 40 CFR 70.7(a)(6)]

8.4 Fee Assessment and Payment

8.4.1 The Permittee shall calculate and pay an annual Permit fee to the Division. The amount of fee shall be determined each year in accordance with the "Procedures for Calculating Air Permit Fees."
[391-3-1-.03(9)]

8.5 Permit Renewal and Expiration

8.5.1 This Permit shall remain in effect for five (5) years from the effective date. The Permit shall become null and void after the expiration date unless a timely and complete renewal application has been submitted to the Division at least six (6) months, but no more than eighteen (18) months prior to the expiration date of the Permit.
[391-3-1-.03(10)(d)1(i), (e)2, and (e)3(ii) and 40 CFR 70.5(a)(1)(iii)]

8.5.2 Permits being renewed are subject to the same procedural requirements, including those for public participation and affected State and EPA review, that apply to initial Permit issuance.
[391-3-1-.03(10)(e)3(i)]

8.5.3 Notwithstanding the provisions in 8.5.1 above, if the Division has received a timely and complete application for renewal, deemed it administratively complete, and failed to reissue the Permit for reasons other than cause, authorization to operate shall continue beyond the expiration date to the point of Permit modification, reissuance, or revocation.
[391-3-1-.03(10)(e)3(iii)]

8.6 Transfer of Ownership or Operation

8.6.1 This Permit is not transferable by the Permittee. Future owners and operators shall obtain a new Permit from the Director. The new Permit may be processed as an administrative amendment if no other change in this Permit is necessary, and provided that a written agreement containing a specific date for transfer of Permit responsibility coverage and liability between the current and new Permittee has been submitted to the Division at least thirty (30) days in advance of the transfer.
[391-3-1-.03(4)]

8.7 Property Rights

8.7.1 This Permit shall not convey property rights of any sort, or any exclusive privileges.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(iv)]

8.8 Submissions

8.8.1 Reports, test data, monitoring data, notifications, annual certifications, and requests for revision and renewal shall be submitted to:

Georgia Department of Natural Resources
Environmental Protection Division
Air Protection Branch
Atlanta Tradeport, Suite 120
4244 International Parkway
Atlanta, Georgia 30354-3908

8.8.2 Any records, compliance certifications, and monitoring data required by the provisions in this Permit to be submitted to the EPA shall be sent to:

Air and EPCRA Enforcement Branch – U. S. EPA Region 4
Sam Nunn Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, Georgia 30303-3104

8.8.3 Any application form, report, or compliance certification submitted pursuant to this Permit shall contain a certification by a responsible official of its truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
[391-3-1-.03(10)(c)2, 40 CFR 70.5(d) and 40 CFR 70.6(c)(1)]

8.8.4 Unless otherwise specified, all submissions under this permit shall be submitted to the Division only.

8.9 Duty to Provide Information

8.9.1 The Permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the Permit application, shall promptly submit such supplementary facts or corrected information to the Division.
[391-3-1-.03(10)(c)5]

8.9.2 The Permittee shall furnish to the Division, in writing, information that the Division may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the Permit, or to determine compliance with the Permit. Upon request, the Permittee shall also furnish to the Division copies of records that the Permittee is required to keep by this Permit or, for information claimed to be confidential, the Permittee may furnish such records directly to the EPA, if necessary, along with a claim of confidentiality.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(v)]

8.10 Modifications

8.10.1 Prior to any source commencing a modification as defined in 391-3-1-.01(pp) that may result in air pollution and not exempted by 391-3-1-.03(6), the Permittee shall submit a Permit application to the Division. The application shall be submitted sufficiently in advance of any critical date involved to allow adequate time for review, discussion, or revision of plans, if necessary. Such application shall include, but not be limited to, information describing the precise nature of the change, modifications to any emission control system, production capacity of the plant before and after the change, and the anticipated completion date of the change. The application shall be in the form of a Georgia air quality Permit application to construct or modify (otherwise known as a SIP application) and shall be submitted on forms supplied by the Division, unless otherwise notified by the Division.
[391-3-1-.03(1) through (8)]

8.11 Permit Revision, Revocation, Reopening and Termination

8.11.1 This Permit may be revised, revoked, reopened and reissued, or terminated for cause by the Director. The Permit will be reopened for cause and revised accordingly under the following circumstances:
[391-3-1-.03(10)(d)1(i)]

a. If additional applicable requirements become applicable to the source and the remaining Permit term is three (3) years or longer. In this case, the reopening shall be completed no later than eighteen (18) months after promulgation of the applicable requirement. A reopening shall not be required if compliance with the applicable requirement is not required until after the date on which the Permit is due to expire;
[391-3-1-.03(10)(e)6(i)(I)]

b. If any additional applicable requirements of the Acid Rain Program become applicable to the source;
[391-3-1-.03(10)(e)6(i)(II)] (Acid Rain sources only)

c. The Director determines that the Permit contains a material mistake or inaccurate statements were made in establishing the emissions standards or other terms or conditions of the Permit; or
[391-3-1-.03(10)(e)6(i)(III) and 40 CFR 70.7(f)(1)(iii)]

d. The Director determines that the Permit must be revised or revoked to assure compliance with the applicable requirements.
[391-3-1-.03(10)(e)6(i)(IV) and 40 CFR 70.7(f)(1)(iv)]

8.11.2 Proceedings to reopen and reissue a Permit shall follow the same procedures as applicable to initial Permit issuance and shall affect only those parts of the Permit for which cause to reopen exists. Reopenings shall be made as expeditiously as practicable.
[391-3-1-.03(10)(e)6(ii)]

8.11.3 Reopenings shall not be initiated before a notice of intent to reopen is provided to the source by the Director at least thirty (30) days in advance of the date the Permit is to be reopened, except that the Director may provide a shorter time period in the case of an emergency.
[391-3-1-.03(10)(e)6(iii)]

8.11.4 All Permit conditions remain in effect until such time as the Director takes final action. The filing of a request by the Permittee for any Permit revision, revocation, reissuance, or termination, or of a notification of planned changes or anticipated noncompliance, shall not stay any Permit condition.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(iii)]

8.11.5 A Permit revision shall not be required for changes that are explicitly authorized by the conditions of this Permit.

8.11.6 A Permit revision shall not be required for changes that are part of an approved economic incentive, marketable Permit, emission trading, or other similar program or process for change which is specifically provided for in this Permit.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(8)]

8.12 Severability

8.12.1 Any condition or portion of this Permit which is challenged, becomes suspended or is ruled invalid as a result of any legal or other action shall not invalidate any other portion or condition of this Permit.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(5)]

8.13 Excess Emissions Due to an Emergency

8.13.1 An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the Permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.
[391-3-1-.03(10)(d)7 and 40 CFR 70.6(g)(1)]

8.13.2 An emergency shall constitute an affirmative defense to an action brought for noncompliance with the technology-based emission limitations if the Permittee demonstrates, through properly signed contemporaneous operating logs or other relevant evidence, that:
[391-3-1-.03(10)(d)7 and 40 CFR 70.6(g)(2) and (3)]

a. An emergency occurred and the Permittee can identify the cause(s) of the emergency;

b. The Permitted facility was at the time of the emergency being properly operated;

c. During the period of the emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards, or other requirements in the Permit; and

d. The Permittee promptly notified the Division and submitted written notice of the emergency to the Division within two (2) working days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

8.13.3 In an enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency shall have the burden of proof.
[391-3-1-.03(10)(d)7 and 40 CFR 70.6(g)(4)]

8.13.4 The emergency conditions listed above are in addition to any emergency or upset provisions contained in any applicable requirement.
[391-3-1-.03(10)(d)7 and 40 CFR 70.6(g)(5)]

8.14 Compliance Requirements

8.14.1 Compliance Certification

The Permittee shall provide written certification to the Division and to the EPA, at least annually, of compliance with the conditions of this Permit. The annual written certification shall be postmarked no later than February 28 of each year and shall be submitted to the Division and to the EPA. The certification shall include, but not be limited to, the following elements:
[391-3-1-.03(10)(d)3 and 40 CFR 70.6(c)(5)]

a. The identification of each term or condition of the Permit that is the basis of the certification;

b. The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent, based on the method or means designated in paragraph c below. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 occurred;

c. The identification of the method(s) or other means used by the owner or operator for determining the compliance status with each term and condition during the certification period;

d. Any other information that must be included to comply with section 113(c)(2) of the Act, which prohibits knowingly making a false certification or omitting material information; and

e. Any additional requirements specified by the Division.

8.14.2 Inspection and Entry

a. Upon presentation of credentials and other documents as may be required by law, the Permittee shall allow authorized representatives of the Division to perform the following:
[391-3-1-.03(10)(d)3 and 40 CFR 70.6(c)(2)]

i. Enter upon the Permittee's premises where a Part 70 source is located or an emissions-related activity is conducted, or where records must be kept under the conditions of this Permit;
ii. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;
iii. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this Permit; and
iv. Sample or monitor any substances or parameters at any location during operating hours for the purpose of assuring Permit compliance or compliance with applicable requirements as authorized by the Georgia Air Quality Act.

b. No person shall obstruct, hamper, or interfere with any such authorized representative while in the process of carrying out his official duties. Refusal of entry or access may constitute grounds for Permit revocation and assessment of civil penalties.[391-3-1-.07 and 40 CFR 70.11(a)(3)(i)]

8.14.3 Schedule of Compliance

a. For applicable requirements with which the Permittee is in compliance, the Permittee shall continue to comply with those requirements.
[391-3-1-.03(10)(c)2 and 40 CFR 70.5(c)(8)(iii)(A)]

b. For applicable requirements that become effective during the Permit term, the Permittee shall meet such requirements on a timely basis unless a more detailed schedule is expressly required by the applicable requirement.
[391-3-1-.03(10)(c)2 and 40 CFR 70.5(c)(8)(iii)(B)]

c. Any schedule of compliance for applicable requirements with which the source is not in compliance at the time of Permit issuance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based.
[391-3-1-.03(10)(c)2 and 40 CFR 70.5(c)(8)(iii)(C)]

8.14.4 Excess Emissions

a. Excess emissions resulting from startup, shutdown, or malfunction of any source which occur though ordinary diligence is employed shall be allowed provided that:
[391-3-1-.02(2)(a)7(i)]

i. The best operational practices to minimize emissions are adhered to;

ii. All associated air pollution control equipment is operated in a manner consistent with good air pollution control practice for minimizing emissions; and

iii. The duration of excess emissions is minimized.

b. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction are prohibited and are violations of Chapter 391-3-1 of the Georgia Rules for Air Quality Control.
[391-3-1-.02(2)(a)7(ii)]

c. The provisions of this condition and Georgia Rule 391-3-1-.02(2)(a)7 shall apply only to those sources which are not subject to any requirement under Georgia Rule 391-3-1-.02(8) – New Source Performance Standards or any requirement of 40 CFR, Part 60, as amended concerning New Source Performance Standards.
[391-3-1-.02(2)(a)7(iii)]

8.15 Circumvention

State Only Enforceable Condition.

8.15.1 The Permittee shall not build, erect, install, or use any article, machine, equipment or process the use of which conceals an emission which would otherwise constitute a violation of an applicable emission standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of the pollutants in the gases discharged into the atmosphere.
[391-3-1-.03(2)(c)]

8.16 Permit Shield

8.16.1 Compliance with the terms of this Permit shall be deemed compliance with all applicable requirements as of the date of Permit issuance provided that all applicable requirements are included and specifically identified in the Permit.
[391-3-1-.03(10)(d)6]

8.16.2 Any Permit condition identified as "State only enforceable" does not have a Permit shield.

8.17 Operational Practices

8.17.1 At all times, including periods of startup, shutdown, and malfunction, the Permittee shall maintain and operate the source, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on any information available to the Division that may include, but is not limited to, monitoring results, observations of the opacity or other characteristics of emissions, review of operating and maintenance procedures or records, and inspection or surveillance of the source.
[391-3-1-.02(2)(a)10]

State Only Enforceable Condition.

8.17.2 No person owning, leasing, or controlling, the operation of any air contaminant sources shall willfully, negligently or through failure to provide necessary equipment or facilities or to take necessary precautions, cause, permit, or allow the emission from said air contamination source or sources, of such quantities of air contaminants as will cause, or tend to cause, by themselves, or in conjunction with other air contaminants, a condition of air pollution in quantities or characteristics or of a duration which is injurious or which unreasonably interferes with the enjoyment of life or use of property in such area of the State as is affected thereby. Complying with Georgia's Rules for Air Quality Control Chapter 391-3-1 and Conditions in this Permit, shall in no way exempt a person from this provision.
[391-3-1-.02(2)(a)1]

8.18 Visible Emissions

8.18.1 Except as may be provided in other provisions of this Permit, the Permittee shall not cause, let, suffer, permit or allow emissions from any air contaminant source the opacity of which is equal to or greater than forty (40) percent.
[391-3-1-.02(2)(b)1]

8.19 Fuel-burning Equipment

8.19.1 The Permittee shall not cause, let, suffer, permit, or allow the emission of fly ash and/or other particulate matter from any fuel-burning equipment with rated heat input capacity of less than 10 million Btu per hour, in operation or under construction on or before January 1, 1972 in amounts equal to or exceeding 0.7 pounds per million BTU heat input.
[391-3-1-.02(2)(d)]

8.19.2 The Permittee shall not cause, let, suffer, permit, or allow the emission of fly ash and/or other particulate matter from any fuel-burning equipment with rated heat input capacity of less than 10 million Btu per hour, constructed after January 1, 1972 in amounts equal to or exceeding 0.5 pounds per million BTU heat input.
[391-3-1-.02(2)(d)]

8.19.3 The Permittee shall not cause, let, suffer, permit, or allow the emission from any fuel-burning equipment constructed or extensively modified after January 1, 1972, visible emissions the opacity of which is equal to or greater than twenty (20) percent except for one six minute period per hour of not more than twenty-seven (27) percent opacity.
[391-3-1-.02(2)(d)]

8.20 Sulfur Dioxide

8.20.1 Except as may be specified in other provisions of this Permit, the Permittee shall not burn fuel containing more than 2.5 percent sulfur, by weight, in any fuel burning source that has a heat input capacity below 100 million Btu's per hour.
[391-3-1-.02(2)(g)]

8.21 Particulate Emissions

8.21.1 Except as may be specified in other provisions of this Permit, the Permittee shall not cause, let, permit, suffer, or allow the rate of emission from any source, particulate matter in total quantities equal to or exceeding the allowable rates shown below. Equipment in operation, or under construction contract, on or before July 2, 1968, shall be considered existing equipment. All other equipment put in operation or extensively altered after said date is to be considered new equipment.
[391-3-1-.02(2)(e)]

a. The following equations shall be used to calculate the allowable rates of emission from new equipment:

$E = 4.1P^{0.67}$; for process input weight rate up to and including 30 tons per hour.
$E = 55P^{0.11} - 40$; for process input weight rate above 30 tons per hour.

b. The following equation shall be used to calculate the allowable rates of emission from existing equipment:

$$E = 4.1P^{0.67}$$

In the above equations, E = emission rate in pounds per hour, and
P = process input weight rate in tons per hour.

8.22 Fugitive Dust
[391-3-1-.02(2)(n)]

8.22.1 Except as may be specified in other provisions of this Permit, the Permittee shall take all reasonable precautions to prevent dust from any operation, process, handling, transportation or storage facility from becoming airborne. Reasonable precautions that could be taken to prevent dust from becoming airborne include, but are not limited to, the following:

a. Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads or the clearing of land;

b. Application of asphalt, water, or suitable chemicals on dirt roads, materials, stockpiles, and other surfaces that can give rise to airborne dusts;

c. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials. Adequate containment methods can be employed during sandblasting or other similar operations;

d. Covering, at all times when in motion, open bodied trucks transporting materials likely to give rise to airborne dusts; and

e. The prompt removal of earth or other material from paved streets onto which earth or other material has been deposited.

8.22.2 The opacity from any fugitive dust source shall not equal or exceed 20 percent.

8.23 Solvent Metal Cleaning

8.23.1 Except as may be specified in other provisions of this Permit, the Permittee shall not cause, suffer, allow, or permit the operation of a cold cleaner degreaser unless the following requirements for control of emissions of the volatile organic compounds are satisfied: [391-3-1-.02(2)(ff)1]

a. The degreaser shall be equipped with a cover to prevent escape of VOC during periods of non-use,

b. The degreaser shall be equipped with a device to drain cleaned parts before removal from the unit,

c. If the solvent volatility is 0.60 psi or greater measured at 100 °F, or if the solvent is heated above 120 °F, then one of the following control devices must be used:

i. The degreaser shall be equipped with a freeboard that gives a freeboard ratio of 0.7 or greater, or

ii. The degreaser shall be equipped with a water cover (solvent must be insoluble in and heavier than water), or

iii. The degreaser shall be equipped with a system of equivalent control, including but not limited to, a refrigerated chiller or carbon adsorption system.

d. Any solvent spray utilized by the degreaser must be in the form of a solid, fluid stream (not a fine, atomized or shower type spray) and at a pressure which will not cause excessive splashing, and

e. All waste solvent from the degreaser shall be stored in covered containers and shall not be disposed of by such a method as to allow excessive evaporation into the atmosphere.

8.24 Incinerators

8.24.1 Except as specified in the section dealing with conical burners, no person shall cause, let, suffer, permit, or allow the emissions of fly ash and/or other particulate matter from any incinerator, in amounts equal to or exceeding the following:
[391-3-1-.02(2)(c)1-4]

a. Units with charging rates of 500 pounds per hour or less of combustible waste, including water, shall not emit fly ash and/or particulate matter in quantities exceeding 1.0 pound per hour.

b. Units with charging rates in excess of 500 pounds per hour of combustible waste, including water, shall not emit fly ash and/or particulate matter in excess of 0.20 pounds per 100 pounds of charge.

8.24.2 No person shall cause, let, suffer, permit, or allow from any incinerator, visible emissions the opacity of which is equal to or greater than twenty (20) percent except for one six minute period per hour of not more than twenty-seven (27) percent opacity.

8.24.3 No person shall cause or allow particles to be emitted from an incinerator which are individually large enough to be visible to the unaided eye.

8.24.4 No person shall operate an existing incinerator unless:

a. It is a multiple chamber incinerator;

b. It is equipped with an auxiliary burner in the primary chamber for the purpose of creating a pre-ignition temperature of 800°F; and

c. It has a secondary burner to control smoke and/or odors and maintain a temperature of at least 1500°F in the secondary chamber.

8.25 Volatile Organic Liquid Handling and Storage

8.25.1 The Permittee shall ensure that each storage tank subject to the requirements of Rule 391-3-1-.02(2)(vv) "Volatile Organic Liquid Handling and Storage" is equipped with submerged fill pipes. For the purposes of this condition and the permit, a submerged fill pipe is defined as any fill pipe with a discharge opening which is within six inches of the tank bottom.
[391-3-1-.02(2)(vv)(1)]

8.26 Use of Any Credible Evidence or Information

8.26.1 Notwithstanding any other provisions of any applicable rule or regulation or requirement of this permit, for the purpose of submission of compliance certifications or establishing whether or not a person has violated or is in violation of any emissions limitation or standard, nothing in this permit or any Emission Limitation or Standard to which it pertains, shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.
[391-3-1-.02(3)(a)]

8.27 Diesel-Fired Internal Combustion Engines

8.27.1 The Permittee shall comply with all applicable provisions of New Source Performance Standards (NSPS) Federal Rule 40 CFR Part 60 Subpart A-"General Provisions" and Subpart IIII-"Standards for Stationary Compression Ignition Internal Combustion Engines," for diesel-fired internal combustion engine(s) manufactured after April 1, 2006 or modified/reconstructed after July 11, 2005. Such requirements include but are not limited to:
[40 CFR 60.4205(b), 391-3-1-.02(8)(b)77]

a. Equip all emergency generator engines with non-resettable hour meters

b. Purchase only diesel fuel with a maximum sulfur content of 15 ppm unless otherwise specified by the Division.

Attachments

A. List of Standard Abbreviations and List of Permit Specific Abbreviations
B. Insignificant Activities Checklist, Insignificant Activities Based on Emission Levels and Generic Emission Groups
C. List of References
D. U.S. EPA Acid Rain Program Permit Application for Phase II NO_X Averaging Plan
E. CAIR Permit Application for SO_2 and NO_X Annual Trading Programs

ATTACHMENT A

List Of Standard Abbreviations

AIRS	Aerometric Information Retrieval System	PM	Particulate Matter
APCD	Air Pollution Control Device	PM_{10} (PM10)	Particulate Matter less than 10 micrometers in diameter
ASTM	American Society for Testing and Materials	PPM (ppm)	Parts per Million
BACT	Best Available Control Technology	PSD	Prevention of Significant Deterioration
BTU	British Thermal Unit	RACT	Reasonably Available Control Technology
CAAA	Clean Air Act Amendments	RMP	Risk Management Plan
CEMS	Continuous Emission Monitoring System	SIC	Standard Industrial Classification
CERMS	Continuous Emission Rate Monitoring System	SIP	State Implementation Plan
CFR	Code of Federal Regulations	SO_2 (SO2)	Sulfur Dioxide
CMS	Continuous Monitoring System(s)	USC	United States Code
CO	Carbon Monoxide	VE	Visible Emissions
COMS	Continuous Opacity Monitoring System	VOC	Volatile Organic Compound
dscf/dscm	Dry Standard Cubic Foot / Dry Standard Cubic Meter		
EPA	United States Environmental Protection Agency		
EPCRA	Emergency Planning and Community Right to Know Act		
gr	Grain(s)		
GPM (gpm)	Gallons per minute		
H_2O (H2O)	Water		
HAP	Hazardous Air Pollutant		
HCFC	Hydro-chloro-fluorocarbon		
MACT	Maximum Achievable Control Technology		
MMBtu	Million British Thermal Units		
MMBtu/hr	Million British Thermal Units per hour		
MVAC	Motor Vehicle Air Conditioner		
MW	Megawatt		
NESHAP	National Emission Standards for Hazardous Air Pollutants		
NO_x (NOx)	Nitrogen Oxides		
NSPS	New Source Performance Standards		
OCGA	Official Code of Georgia Annotated		

List of Permit Specific Abbreviations

PAC	Powdered Activated Carbon	FGD	Flue Gas Desulfurization
ESP	Electrostatic Precipitator	SCR	Selective Catalytic Reduction
PCB	Polychlorinated Biphenyl		

ATTACHMENT B

NOTE: Attachment B contains information regarding insignificant emission units/activities and groups of generic emission units/activities in existence at the facility at the time of Permit issuance. Future modifications or additions of insignificant emission units/activities and equipment that are part of generic emissions groups may not necessarily cause this attachment to be updated.

INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
Mobile Sources	1. Cleaning and sweeping of streets and paved surfaces	X
Combustion Equipment	1. Fire fighting and similar safety equipment used to train fire fighters or other emergency personnel.	X
	2. Small incinerators that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act and are not considered a "designated facility" as specified in 40 CFR 60.32e of the Federal emissions guidelines for Hospital/Medical/Infectious Waste Incinerators, that are operating as follows: i) Less than 8 million BTU/hr heat input, firing types 0, 1, 2, and/or 3 waste.	0
	ii) Less than 8 million BTU/hr heat input with no more than 10% pathological (type 4) waste by weight combined with types 0, 1, 2, and/or 3 waste.	0
	iii) Less than 4 million BTU/hr heat input firing type 4 waste. (Refer to 391-3-1-.03(10)(g)2.(ii) for descriptions of waste types)	0
	3. Open burning in compliance with Georgia Rule 391-3-1-.02 (5).	X
	4. Stationary engines burning: i) Natural gas, LPG, gasoline, dual fuel, or diesel fuel which are used exclusively as emergency generators shall not exceed 500 hours per year or 200 hours per year if subject to Georgia Rule 391-3-1-.02(2)(mmm).7	4
	ii) Natural gas, LPG, and/or diesel fueled generators used for emergency, peaking, and/or standby power generation, where the combined peaking and standby power generation do not exceed 200 hours per year.	0
	iii) Natural gas, LPG, and/or diesel fuel used for other purposes, provided that the output of each engine does not exceed 400 horsepower and that no individual engine operates for more than 2,000 hours per year.	2
	iv) Gasoline used for other purposes, provided that the output of each engine does not exceed 100 horsepower and that no individual engine operates for more than 500 hours per year.	0
Trade Operations	1. Brazing, soldering, and welding equipment, and cutting torches related to manufacturing and construction activities whose emissions of hazardous air pollutants (HAPs) fall below 1,000 pounds per year.	X
Maintenance, Cleaning, and Housekeeping	1. Blast-cleaning equipment using a suspension of abrasive in water and any exhaust system (or collector) serving them exclusively.	0
	2. Portable blast-cleaning equipment.	1
	3. Non-Perchloroethylene Dry-cleaning equipment with a capacity of 100 pounds per hour or less of clothes.	0
	4. Cold cleaners having an air/vapor interface of not more than 10 square feet and that do not use a halogenated solvent.	9
	5. Non-routine clean out of tanks and equipment for the purposes of worker entry or in preparation for maintenance or decommissioning.	X
	6. Devices used exclusively for cleaning metal parts or surfaces by burning off residual amounts of paint, varnish, or other foreign material, provided that such devices are equipped with afterburners.	0
	7. Cleaning operations: Alkaline phosphate cleaners and associated cleaners and burners.	0

INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
Laboratories and Testing	1. Laboratory fume hoods and vents associated with bench-scale laboratory equipment used for physical or chemical analysis.	6
	2. Research and development facilities, quality control testing facilities and/or small pilot projects, where combined daily emissions from all operations are not individually major or are support facilities not making significant contributions to the product of a collocated major manufacturing facility.	0
Pollution Control	1. Sanitary waste water collection and treatment systems, except incineration equipment or equipment subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	9
	2. On site soil or groundwater decontamination units that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
	3. Bioremediation operations units that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
	4. Landfills that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
Industrial Operations	1. Concrete block and brick plants, concrete products plants, and ready mix concrete plants producing less than 125,000 tons per year.	0
	2. Any of the following processes or process equipment which are electrically heated or which fire natural gas, LPG or distillate fuel oil at a maximum total heat input rate of not more than 5 million BTU's per hour: i) Furnaces for heat treating glass or metals, the use of which do not involve molten materials or oil-coated parts.	0
	ii) Porcelain enameling furnaces or porcelain enameling drying ovens.	0
	iii) Kilns for firing ceramic ware.	0
	iv) Crucible furnaces, pot furnaces, or induction melting and holding furnaces with a capacity of 1,000 pounds or less each, in which sweating or distilling is not conducted and in which fluxing is not conducted utilizing free chlorine, chloride or fluoride derivatives, or ammonium compounds.	0
	v) Bakery ovens and confection cookers.	0
	vi) Feed mill ovens.	0
	vii) Surface coating drying ovens	0
	3. Carving, cutting, routing, turning, drilling, machining, sawing, surface grinding, sanding, planing, buffing, shot blasting, shot peening, or polishing; ceramics, glass, leather, metals, plastics, rubber, concrete, paper stock or wood, also including roll grinding and ground wood pulping stone sharpening, provided that: i) Activity is performed indoors; & ii) No significant fugitive particulate emissions enter the environment; & iii) No visible emissions enter the outdoor atmosphere.	X
	4. Photographic process equipment by which an image is reproduced upon material sensitized to radiant energy (e.g., blueprint activity, photographic developing and microfiche).	0
	5. Grain, food, or mineral extrusion processes	0
	6. Equipment used exclusively for sintering of glass or metals, but not including equipment used for sintering metal-bearing ores, metal scale, clay, fly ash, or metal compounds.	0
	7. Equipment for the mining and screening of uncrushed native sand and gravel.	0
	8. Ozonization process or process equipment.	0
	9. Electrostatic powder coating booths with an appropriately designed and operated particulate control system.	0
	10. Activities involving the application of hot melt adhesives where VOC emissions are less than 5 tons per year and HAP emissions are less than 1,000 pounds per year.	0
	11. Equipment used exclusively for the mixing and blending water-based adhesives and coatings at ambient temperatures.	0
	12. Equipment used for compression, molding and injection of plastics where VOC emissions are less than 5 tons per year and HAP emissions are less than 1,000 pounds per year.	0
	13. Ultraviolet curing processes where VOC emissions are less than 5 tons per year and HAP emissions are less than 1,000 pounds per year.	0

INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
Storage Tanks and Equipment	1. All petroleum liquid storage tanks storing a liquid with a true vapor pressure of equal to or less than 0.50 psia as stored.	2
	2. All petroleum liquid storage tanks with a capacity of less than 40,000 gallons storing a liquid with a true vapor pressure of equal to or less than 2.0 psia as stored that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	2
	3. All petroleum liquid storage tanks with a capacity of less than 10,000 gallons storing a petroleum liquid.	28
	4. All pressurized vessels designed to operate in excess of 30 psig storing petroleum fuels that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
	5. Gasoline storage and handling equipment at loading facilities handling less than 20,000 gallons per day or at vehicle dispensing facilities that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	1
	6. Portable drums, barrels, and totes provided that the volume of each container does not exceed 550 gallons.	<150
	7. All chemical storage tanks used to store a chemical with a true vapor pressure of less than or equal to 10 millimeters of mercury (0.19 psia).	7

INSIGNIFICANT ACTIVITIES BASED ON EMISSION LEVELS

Description of Emission Units / Activities	Quantity
Cooling Towers	4

ATTACHMENT B (continued)

GENERIC EMISSION GROUPS

Emission units/activities appearing in the following table are subject only to one or more of Georgia Rules 391-3-1-.02 (2) (b), (e) &/or (n). Potential emissions of particulate matter, from these sources based on TSP, are less than 25 tons per year per process line or unit in each group. Any emissions unit subject to a NESHAP, NSPS, or any specific Air Quality Permit Condition(s) are not included in this table.

Description of Emissions Units / Activities	Number of Units (if appropriate)	Applicable Rules		
		Opacity Rule (b)	PM from Mfg Process Rule (e)	Fugitive Dust Rule (n)
n/a				

The following table includes groups of fuel burning equipment subject only to Georgia Rules 391-3-1-.02 (2) (b) & (d).Any emissions unit subject to a NESHAP, NSPS, or any specific Air Quality Permit Condition(s) are not included in this table.

Description of Fuel Burning Equipment	Number of Units
Fuel burning equipment with a rated heat input capacity of less than 10 million BTU/hr burning only natural gas and/or LPG.	0
Fuel burning equipment with a rated heat input capacity of less than 5 million BTU/hr, burning only distillate fuel oil, natural gas and/or LPG.	0
Any fuel burning equipment with a rated heat input capacity of 1 million BTU/hr or less.	0

ATTACHMENT C

LIST OF REFERENCES

1. The Georgia Rules for Air Quality Control Chapter 391-3-1. All Rules cited herein which begin with 391-3-1 are State Air Quality Rules.

2. Title 40 of the Code of Federal Regulations; specifically 40 CFR Parts 50, 51, 52, 60, 61, 63, 64, 68, 70, 72, 73, 75, 76 and 82. All rules cited with these parts are Federal Air Quality Rules.

3. ***Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, Procedures for Testing and Monitoring Sources of Air Pollutants.***

4. ***Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, Procedures for Calculating Air Permit Fees.***

5. Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources. This information may be obtained from EPA's TTN web site at *www.epa.gov/ttn/chief/ap42/index.html.*

6. The latest properly functioning version of EPA's **TANKS** emission estimation software. The software may be obtained from EPA's TTN web site at *www.epa.gov/ttn/chief/software/tanks/index.html.*

7. The Clean Air Act (42 U.S.C. 7401 et seq).

8. White Paper for Streamlined Development of Part 70 Permit Applications, July 10, 1995 (White Paper #1).

9. White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program, March 5, 1996 (White Paper #2)

ATTACHMENT D

U.S. EPA ACID RAIN PROGRAM PERMIT APPLICATION FOR PHASE II NO_X AVERAGING PLAN

RECEIVED

DEC 2 2008

AIR PROTECTION BRANCH

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Phase II NO_x Averaging Plan

For more information, see instructions and refer to 40 CFR 76.11

This submission is: [ ] New [X] Revised

STEP 1

Identify the units participating in this averaging plan by plant name, State, and boiler ID# from NADB. In column (a), fill in each unit's applicable emission limitation from 40 CFR 76.5, 76.6, or 76.7. In column (b), assign an alternative contemporaneous annual emissions limitation (ACEL) in lb/mmBtu to each unit. In column (c), assign an annual heat input limitation in mmBtu to each unit. Continue to page 3 if necessary.

Plant Name	State	ID#	(a) Emission Limitation	(b) ACEL	(c) Annual Heat Input Limit
See Page 3.					

STEP 2

Use the formula to enter the Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan and the Btu-weighted annual average emission rate for the same units if they are operated in compliance with 40 CFR 76.5, 76.6, or 76.7. The former must be less than or equal to the latter.

Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan		Btu-weighted annual average emission rate for same units operated in compliance with 40 CFR 76.5, 76.6 or 76.7
0.46	≤	0.46

$$\frac{\sum_{i=1}^{n}(R_{Li}\times HI_i)}{\sum_{i=1}^{n} HI_i} \le \frac{\sum_{i=1}^{n}[R_{li}\times HI_i]}{\sum_{i=1}^{n} HI_i}$$

Where,

R_{Li} = Alternative contemporaneous annual emission limitation for unit i, in lb/mmBtu, as specified in column (b) of Step 1;

R_{li} = Applicable emission limitation for unit i, in lb/mmBtu, as specified in column (a) of Step 1;

HI_i = Annual heat input for unit i, in mmBtu, as specified in column (c) of Step 1;

n = Number of units in the averaging plan

Southern Company Averaging Plan

Participating Plants
Plant Name (from Step 1)

STEP 3

Mark one of the two options and enter dates.

☐ This plan is effective for calendar year ________ through calendar year ________ unless notification to terminate the plan is given.

☒ Treat this plan as [5] identical plans, each effective for one calendar year for the following calendar years: 2009, 2010, 2011, 2012 and 2013 unless notification to terminate one or more of these plans is given.

STEP 4

Read the special provisions and certification, enter the name of the designated representative, and sign and date.

Special Provisions

Emission Limitations

Each affected unit in an approved averaging plan is in compliance with the Acid Rain emission limitation for NO_x under the plan only if the following requirements are met:

(i) For each unit, the unit's actual annual average emission rate for the calendar year, in lb/mmBtu, is less than or equal to its alternative contemporaneous annual emission limitation in the averaging plan, and
(a) For each unit with an alternative contemporaneous emission limitation less stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year does not exceed the annual heat input limit in the averaging plan,
(b) For each unit with an alternative contemporaneous emission limitation more stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year is not less than the annual heat input limit in the averaging plan, or
(ii) If one or more of the units does not meet the requirements of (i), the designated representative shall demonstrate, in accordance with 40 CFR 76.11(d)(1)(ii)(A) and (B), that the actual Btu-weighted annual average emission rate for the units in the plan is less than or equal to the Btu-weighted annual average rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations in 40 CFR 76.5, 76.6, or 76.7.
(iii) If there is a successful group showing of compliance under 40 CFR 76.11(d)(1)(ii)(A) and (B) for a calendar year, then all units in the averaging plan shall be deemed to be in compliance for that year with their alternative contemporaneous emission limitations and annual heat input limits under (i).

Liability

The owners and operators of a unit governed by an approved averaging plan shall be liable for any violation of the plan or this section at that unit or any other unit in the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and sections 113 and 411 of the Act.

Termination

The designated representative may submit a notification to terminate an approved averaging plan, in accordance with 40 CFR 72.40(d), no later than October 1 of the calendar year for which the plan is to be terminated.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Chris M. Hobson	
Signature [signature]	Date 7/15/08

Southern Company Averaging Plan Participating Plants
Plant Name (from Step 1) as Listed in Step 1.

STEP 1
Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID #	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Barry	AL	1	0.40	0.57	9,860,460
Barry	AL	2	0.40	0.57	8,697,917
Barry	AL	3	0.40	0.57	15,390,498
Barry	AL	4	0.40	0.45	26,579,698
Barry	AL	5	0.40	0.45	41,811,371
Bowen	GA	1	0.45	0.42	43,857,264
Bowen	GA	2	0.45	0.43	52,033,363
Bowen	GA	3	0.45	0.43	60,747,005
Bowen	GA	4	0.45	0.43	60,245,171
Branch	GA	1	0.68	0.99	15,903,035
Branch	GA	2	0.50	0.72	20,954,063
Branch	GA	3	0.68	0.84	34,483,187
Branch	GA	4	0.68	0.84	29,893,099
Crist	FL	4	0.45	0.52	5,306,563
Crist	FL	5	0.45	0.60	5,321,833
Crist	FL	6	0.50	0.45	22,068,817
Crist	FL	7	0.50	0.45	36,700,987
Daniel	MS	1	0.45	0.33	40,792,453
Daniel	MS	2	0.45	0.33	34,210,453
Gadsden	AL	1	0.45	0.75	2,568,523
Gadsden	AL	2	0.45	0.75	3,084,694
Gaston	AL	1	0.50	0.52	15,475,515
Gaston	AL	2	0.50	0.52	13,226,420
Gaston	AL	3	0.50	0.52	17,263,124
Gaston	AL	4	0.50	0.52	16,744,074
Gaston	AL	5	0.45	0.48	56,376,964
Gorgas	AL	6	0.46	0.55	5,698,165
Gorgas	AL	7	0.46	0.55	6,140,227
Gorgas	AL	8	0.40	0.52	13,186,388
Gorgas	AL	9	0.40	0.52	14,567,087
Gorgas	AL	10	0.40	0.52	55,157,733

Southern Company Averaging Plan Participating Plants as Listed in Step 1.
Plant Name (from Step 1)

STEP 1
Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID #	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Greene Co	AL	1	0.68	0.60	16,688,168
Greene Co	AL	2	0.46	0.60	19,915,731
Hammond	GA	1	0.50	0.83	6,702,621
Hammond	GA	2	0.50	0.83	7,697,469
Hammond	GA	3	0.50	0.83	6,610,570
Hammond	GA	4	0.50	0.45	29,007,730
Kraft	GA	1	0.45	0.58	3,195,641
Kraft	GA	2	0.45	0.58	2,991,096
Kraft	GA	3	0.45	0.58	5,936,838
L. Smith	FL	1	0.40	0.62	13,643,808
L. Smith	FL	2	0.40	0.44	14,784,899
McDonough	GA	1	0.45	0.42	16,633,061
McDonough	GA	2	0.45	0.42	16,753,801
McIntosh	GA	1	0.50	0.86	9,215,784
Miller	AL	1	0.46	0.37	54,272,966
Miller	AL	2	0.46	0.37	52,981,813
Miller	AL	3	0.46	0.28	58,020,776
Miller	AL	4	0.46	0.28	56,910,001
Mitchell	GA	3	0.45	0.62	6,001,510
Scherer	GA	1	0.40	0.50	71,791,890
Scherer	GA	2	0.40	0.50	71,474,044
Scherer	GA	3	0.45	0.29	53,390,136
Scherer	GA	4	0.40	0.30	53,390,136
Scholz	FL	1	0.50	0.68	2,083,631
Scholz	FL	2	0.50	0.77	2,118,168
Wansley	GA	1	0.45	0.41	63,896,521
Wansley	GA	2	0.45	0.42	56,607,431
Watson	MS	4	0.50	0.60	13,463,120
Watson	MS	5	0.50	0.42	35,382,214
Yates	GA	1	0.45	0.48	5,477,394
Yates	GA	2	0.45	0.48	4,879,349
Yates	GA	3	0.45	0.48	4,830,444
Yates	GA	4	0.45	0.40	8,031,999
Yates	GA	5	0.45	0.40	7,240,618
Yates	GA	6	0.45	0.33	21,932,927
Yates	GA	7	0.45	0.30	19,834,248

19764

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2012

Acid Rain Permit Application

RECEIVED

SEP 29 2010

AIR PROTECTION BRANCH

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ~ new ~ revised X for Acid Rain permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name: Scherer	State: GA	Plant Code: 6257

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
1	Yes
2	Yes
3	Yes
4	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Facility (Source) Name (from STEP 1): Scherer

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;
(2) The owners and operators of each affected source and each affected unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

Sulfur Dioxide Requirements, Cont'd.

STEP 3, Cont'd.

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the

submission of a new certificate of representation changing the designated representative;

STEP 3, Cont'd.

Recordkeeping and Reporting Requirements, Cont'd.

(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

STEP 3, Cont'd.

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating

Effect on Other Authorities, Cont'd.

to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a source can hold; *provided,* that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements
under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4
Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Charles H. Huling	
Signature Charles H. Huling	Date 9/28/10

ATTACHMENT E

CAIR PERMIT APPLICATION FOR SO_2 and NO_X ANNUAL TRADING PROGRAMS

2070 00008

CAIR Permit Application

(for sources covered under a CAIR SIP)

For more information, refer to 40 CFR 96.121, 96.122, 96.221, 96.222, 96.321, and 96.322

RECEIVED
DEC 18 2008
18674
AIR PROTECTION BRANCH

This submission is: X New Revised

STEP 1
Identify the source by plant name, State, and ORIS or facility code

Plant Name	State	ORIS/Facility Code
Scherer	GA	6257

STEP 2
Enter the unit ID# for each CAIR unit and indicate to which CAIR programs each unit is subject (by placing an "X" in the column)

Unit ID#	NO_X Annual	SO_2	NO_X Ozone Season
1	X	X	
2	X	X	
3	X	X	
4	X	X	

STEP 3
Read the standard requirements and the certification, enter the name of the CAIR designated representative, and sign and date

Standard Requirements

(a) Permit Requirements.

(1) The CAIR designated representative of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) required to have a title V operating permit and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under §96.122, §96.222, and §96.322 (as applicable) in accordance with the deadlines specified in §96.121, §96.221, and §96.321 (as applicable); and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) required to have a title V operating permit and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CC, CCC, and CCCC (as applicable) of 40 CFR part 96 for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart II, III, and IIII (as applicable) of 40 CFR part 96, the owners and operators of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) that is not otherwise required to have a title V operating permit and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CC, CCC, and CCCC (as applicable) of 40 CFR part 96 for such CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) and such CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable).

STEP 3, continued

(b) Monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the CAIR designated representative, of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96.

(2) The emissions measurements recorded and reported in accordance with subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96 shall be used to determine compliance by each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) with the CAIR NO_X emissions limitation, CAIR SO_2 emissions limitation, and CAIR NO_X Ozone Season emissions limitation (as applicable) under paragraph (c) of §96.106, §96.206, and §96.306 (as applicable).

(c) Nitrogen oxides emissions requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall hold, in the source's compliance account, CAIR NO_X allowances available for compliance deductions for the control period under §96.154(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X units at the source, as determined in accordance with subpart HH of 40 CFR part 96.

(2) A CAIR NO_X unit shall be subject to the requirements under paragraph (c)(1) of §96.106 for the control period starting on the later of January 1, 2009 or the deadline for meeting the unit's monitor certification requirements under §96.170(b)(1), (2), or (5) and for each control period thereafter.

(3) A CAIR NO_X allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of §96.106, for a control period in a calendar year before the year for which the CAIR NO_X allowance was allocated.

(4) CAIR NO_X allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Allowance Tracking System accounts in accordance with subparts FF, GG, and II of 40 CFR part 96.

(5) A CAIR NO_X allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_X Annual Trading Program. No provision of the CAIR NO_X Annual Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.105 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR NO_X allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart EE, FF, GG, or II of 40 CFR part 96, every allocation, transfer, or deduction of a CAIR NO_X allowance to or from a CAIR NO_X source's compliance account is incorporated automatically in any CAIR permit of the source that includes the CAIR NO_X unit.

Sulfur dioxide emission requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall hold, in the source's compliance account, a tonnage equivalent of CAIR SO_2 allowances available for compliance deductions for the control period under §96.254(a) and (b) not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO_2 units at the source, as determined in accordance with subpart HHH of 40 CFR part 96.

(2) A CAIR SO_2 unit shall be subject to the requirements under paragraph (c)(1) of §96.206 for the control period starting on the later of January 1, 2010 or the deadline for meeting the unit's monitor certification requirements under §96.270(b)(1), (2), or (5) and for each control period thereafter.

(3) A CAIR SO_2 allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of §96.206, for a control period in a calendar year before the year for which the CAIR SO_2 allowance was allocated.

(4) CAIR SO_2 allowances shall be held in, deducted from, or transferred into or among CAIR SO_2 Allowance Tracking System accounts in accordance with subparts FFF, GGG, and III of 40 CFR part 96.

(5) A CAIR SO_2 allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO_2 Trading Program. No provision of the CAIR SO_2 Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.205 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR SO_2 allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart FFF, GGG, or III of 40 CFR part 96, every allocation, transfer, or deduction of a CAIR SO_2 allowance to or from a CAIR SO_2 source's compliance account is incorporated automatically in any CAIR permit of the source that includes the CAIR SO_2 unit.

Nitrogen oxides ozone season emissions requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, CAIR NO_X Ozone Season allowances available for compliance deductions for the control period under §96.354(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X Ozone Season units at the source, as determined in accordance with subpart HHHH of 40 CFR part 96.

(2) A CAIR NO_X Ozone Season unit shall be subject to the requirements under paragraph (c)(1) of §96.306 for the control period starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under §96.370(b)(1), (2), (3) or (7) and for each control period thereafter.

(3) A CAIR NO_X Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of §96.306, for a control period in a calendar year before the year for which the CAIR NO_X Ozone Season allowance was allocated.

(4) CAIR NO_X Ozone Season allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Ozone Season Allowance Tracking System accounts in accordance with subparts FFFF, GGGG, and IIII of 40 CFR part 96.

(5) A CAIR NO_X allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_X Ozone Season Trading Program. No provision of the CAIR NO_X Ozone Season Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.305 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR NO_X allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart EEEE, FFFF, GGGG, or IIII of 40 CFR part 96, every allocation, transfer, or deduction of a CAIR NO_X Ozone Season allowance to or from a CAIR NO_X Ozone Season source's compliance account is incorporated automatically in any CAIR permit of the source.

STEP 3, continued

(d) Excess emissions requirements.
If a CAIR NO_X source emits nitrogen oxides during any control period in excess of the CAIR NO_X emissions limitation, then:
(1) The owners and operators of the source and each CAIR NO_X unit at the source shall surrender the CAIR NO_X allowances required for deduction under §96.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

If a CAIR SO_2 source emits sulfur dioxide during any control period in excess of the CAIR SO_2 emissions limitation, then:
(1) The owners and operators of the source and each CAIR SO_2 unit at the source shall surrender the CAIR SO_2 allowances required for deduction under §96.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

If a CAIR NO_X Ozone Season source emits nitrogen oxides during any control period in excess of the CAIR NO_X Ozone Season emissions limitation, then:
(1) The owners and operators of the source and each CAIR NO_X Ozone Season unit at the source shall surrender the CAIR NO_X Ozone Season allowances required for deduction under §96.354(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(e) Recordkeeping and Reporting Requirements.
(1) Unless otherwise provided, the owners and operators of the CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.
(i) The certificate of representation under §96.113, §96.213, and §96.313 (as applicable) for the CAIR designated representative for the source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §96.113, §96.213, and §96.313 (as applicable) changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96, provided that to the extent that subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable).
(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable) or to demonstrate compliance with the requirements of the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable).
(2) The CAIR designated representative of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) at the source shall submit the reports required under the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable) including those under subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96.

(f) Liability.
(1) Each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) and each NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) shall meet the requirements of the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable).
(2) Any provision of the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable) that applies to a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) or the CAIR designated representative of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) shall also apply to the owners and operators of such source and of the CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X Ozone Season units (as applicable) at the source.
(3) Any provision of the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable) that applies to a CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) or the CAIR designated representative of a CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) shall also apply to the owners and operators of such unit.

Scherer Plant Name (from Step 1)

STEP 3, continued

(g) Effect on Other Authorities.
No provision of the CAIR NO_X Annual Trading Program, CAIR SO_2 Trading Program, and CAIR NO_X Ozone Season Trading Program (as applicable), a CAIR permit application, a CAIR permit, or an exemption under §96.105, §96.205, and §96.305 (as applicable) shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X Ozone Season source (as applicable) or CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X Ozone Season unit (as applicable) from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

Certification

I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Charles H. Huling Name	
Signature Charles H. Huling	12/12/2008 Date

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AIR PROTECTION BRANCH

GreenLaw
Giving Georgia's Environment Its Day In Court

Mr. James A. Capp
Chief, Air Protection Branch
Georgia Environmental Protection Division
4244 International Parkway, Atlanta Tradeport – Suite 120
Atlanta, Georgia 30354

Re: Draft Renewal Title V Major Source Operating Permit for the Scherer Steam-Electric Generating Plant, Permit No. 4911-207-0008-V-03-0

Dear Mr. Capp:

GreenLaw and the Southern Environmental Law Center, on behalf of themselves and the Sierra Club[1] (collectively, "Commenters"), respectfully submit the following comments on the draft Major Source Operating Permit ("Draft Permit") for Georgia Power Company's Scherer Steam-Electric Generating Plant. The Draft Permit has been placed on public notice for Clean Air Act ("CAA" or "Act") Title V permit renewal by the Georgia Environmental Protection Division ("EPD"). We appreciate the opportunity to submit these comments.

I. Background

The Scherer Plant ("Plant") in Juliette, Georgia is owned and operated by Georgia Power Company ("GPC"). The area surrounding the facility is designated as nonattainment for the 2008 8-hour ozone and 1997 $PM_{2.5}$ National Ambient Air Quality Standards ("NAAQS"). Draft Permit Narrative at 2. The Plant is GPC's largest coal-fired facility, with a maximum expected operating capacity of 3,564 megawatts ("MW"). The Plant emits more CO_2 annually than any power plant in the nation. Environmental Integrity Project, <u>Getting Warmer: U.S. CO2 Emissions from Power Plants Emissions Rise 5.6% in 2010</u>, at 2 (Feb. 18, 2011) (Ex. 1). The

[1] Sierra Club is a national nonprofit organization with over 625,000 members nationwide. The Georgia chapter has 10,000 members in Georgia, some of whom live, work, and recreate in the vicinity of Plant Scherer and/or in areas impacted by emissions from the Plant. The mission of Sierra Club is to explore, enjoy and protect the wild places of the earth, practice and promote the responsible use of the earth's ecosystems and resources, educate and enlist humanity to protect and restore the quality of the national and human environment, and use all lawful means to carry out these objectives.

EXHIBIT
B

Plant's four coal-fired boiler units ("Units") began operation between 1982 and 1989, and emit significantly more SO_2, NO_X and other air pollutants than more modern coal-fired plants. Plant Scherer is second in the nation for annual health impacts, causing 175 premature deaths, 125 hospital admissions, and 245 heart attacks. Clean Air Task Force, The Toll from Coal at 14 (Sept. 2010) (Ex. 2).

The previous Title V permit for the Plant expired on January 1, 2011. 2005 Title V Permit at 1. EPD received GPC's application for renewal of the Title V permit for the Plant on June 28, 2010. Narrative at 1. On September 20, 2011, EPD issued for public notice the Draft Permit and an accompanying Narrative for this facility. The deadline for public comment is October 21, 2011.

Plant Scherer is in the process of being equipped with modern pollution controls as required under Georgia's Multipollutant Rule, Georgia Air Quality Rule 391-3-1-.02(2)(sss). According to EPD, Rule (sss) "was originally intended to coordinate the necessary electric utility plant emission reductions of NO_X, SO_2, and mercury of the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR), as well as 8-hr ozone and annual $PM_{2.5}$ nonattainment planning needs." EPD, Responses to Comments, Proposed Revisions to Air Quality Rules at E-7 (May 2011) (Ex. 3). The Rule "was crafted ... to maximize the multi-pollutant emissions co-benefits of specifying the required control technology in the shortest period of time while also considering the limitations on construction resources and scheduled outages." Id. Under the Rule as revised in June 2011, Plant Scherer is required to equip and operate each of its Units with selective catalytic reduction (for control of NO_X), flue gas desulfurization (for control of SO_2), sorbent injection and a baghouse (for control of mercury and particulate matter) on a staggered basis during the permit's term, as follows:

Unit 03	July 1, 2011
Unit 04	December 31, 2012
Unit 02	December 31, 2013
Unit 01	December 31, 2014

See Ga. Comp. Rules & Regs. r. 391-3-1-.02(2)(sss)6(i), 9(i), 11(ii), & 12(iii).

A companion rule, Georgia Air Quality Rule 391-3-1-.02(uuu), requires Plant Scherer to achieve a 95 percent reduction of SO_2 emissions from each Unit following installation of the control technology required under Rule (sss).[2] On July 20, 2010, EPD submitted Rule (uuu) to the United States Environmental Protection Agency ("EPA") for approval into Georgia's State Implementation Plan ("SIP"). EPD has not submitted Rule (sss) for SIP approval. EPD takes the position that Rule (sss) "was not adopted in order to satisfy any federal regulatory requirements," even though EPD acknowledges that the Multipollutant Rule is "intended to coordinate the requirements of various federal rules." EPD, Response to Public Comments at E-8 (May 2011) (Ex. 3).

While Rules (sss) and (uuu) require significant pollution control installations and accompanying emission reductions during the renewal term, the beneficial impacts of these requirements are crucially undermined by the Draft Permit's provisions on excess emissions. Neither the operation of the control equipment nor the mandated SO_2 reductions are required during periods of startup, shutdown or malfunction provided certain criteria are met. See Draft Permit at Conditions 3.4.14b., c., e. & 3.4.19b., c., e. (requirements do not apply during periods of startup, shutdown, or malfunction provided such periods are consistent with excess emissions rule, Georgia Air Quality Rule 391-3-1-.02(2)(a)7). Moreover, those criteria are so broadly and vaguely worded – and the terms startup, shutdown and malfunction so loosely defined – that virtually any excess emission can be characterized as allowable, whether or not such emissions could have been planned for and prevented.[3] Furthermore, they reveal an embedded contradiction: for an excess emission to be allowable during a startup, shutdown or malfunction episode, the facility has to show, among other things, that "all associated air pollution control equipment is operated in a manner consistent with good air pollution control practice for minimizing emissions." Draft Permit at Condition 8.4.14. See also Georgia Air Quality Rule 391-3-1-.02(2)(a)7(i). Yet Draft Condition 3.4.14 allows the facility to cease operating its control equipment in those same circumstances.

As discussed in Section VI infra, the Draft Permit should be revised to eliminate any affirmative defense for excess emissions during startup, shutdown or malfunction. However, to the extent an affirmative defense is retained, the final permit must make clear that operation of control equipment in a manner consistent with good practices for minimizing emissions is

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[2] The requirements of Rules (sss) and (uuu) are set forth in Conditions 3.4.14 and 3.4.19, respectively, of the Draft Permit. However, as discussed in Section V.d.i, infra, the effective dates for Scherer Unit 3 must be revised to make them consistent with the recent amendments to the Rules.

[3] This is not an illusory concern. In past citizen enforcement efforts, GPC has argued that *all* of its reported exceedances were not Clean Air Violations because they occurred during periods of startup, shutdown or malfunction. See, e.g., Sierra Club, et al. v. Georgia Power Company, 443 F.3d 1346, 1350 (11th Cir. 2006) (GPC claimed that approximately 4,000 opacity exceedances over four-year span were allowable because they occurred during startup, shutdown or malfunction) (Ex. 4).

always a required element. Contradictory language like that contained in Conditions 3.4.14 and 3.4.19 of the Draft Permit should be stricken.

II. Regulatory Framework

All major stationary sources of air pollution are required to apply for operating permits under Title V of the CAA. These permits must include emission limitations and other conditions necessary to assure continuous compliance with all applicable requirements of the Act, including the requirements of the applicable State Implementation Plan ("SIP"). See 42 U.S.C. §§ 7661a(a) and 7661c(a). The Title V operating permit program does not generally impose new substantive air quality control requirements but does require that permits contain monitoring, recordkeeping, reporting, and other requirements to assure continuous compliance by sources with all existing applicable emission control requirements. 57 Fed. Reg. 32250, 32251 (July 21, 1992) (EPA final action promulgating Part 70 rule). One purpose of the Title V program is to "enable the source, states, EPA, and the public to better understand the requirements to which the source is subject, and whether the source is meeting those requirements." Id. Thus, the Title V program is a vehicle to ensure appropriate application of and compliance with applicable CAA requirements.

The regulations require each Title V permit to include "emissions limitations and standards and operational requirements and limitations necessary to assure compliance with *all applicable requirements* at the time of permit issuance." See Ga. Comp. R. & Regs. r. 391-3-1-.03(10)(d)1(i) (incorporating by reference 40 C.F.R. § 70.6(a)) (emphasis added). Permits must also include "[a]ll emissions monitoring and analysis procedures or test methods required," and "periodic monitoring sufficient to yield reliable data from the relevant time period that is representative of the source's compliance with the permit." See Ga. Comp. R. & Regs. r. 391-3-1-.03(10)(d)3 (incorporating by reference 40 C.F.R. § 70.6(c)). Monitoring requirements must "assure use of terms, test methods, units, averaging periods, and other statistical conventions consistent with the applicable requirement." Id.; see 40 C.F.R. § 70.6(c)(1) (requiring "compliance certification, testing, monitoring, reporting and recordkeeping requirements sufficient to assure compliance with the terms and conditions of the permit").

A Title V permit is issued for a term of no more than five years, 40 C.F.R. § 70.6(a), and the applicant must submit an application for renewal of the permit "at least 6 months prior to the date of permit expiration, or such other longer time as may be approved by the Administrator that ensures that the term of the permit will not expire before the permit is renewed." 40 C.F.R. § 70.5(a)(1)(iii). Permit renewals are subject to the same procedural requirements, including those for public participation and EPA review that apply to initial permit issuance. 40 C.F.R. §

70.7(c)(1)(i). Permitting authorities should analyze timely filed renewal applications and issue renewed permits *prior to expiration* of the existing Title V permit.

III. The Draft Permit is Incomplete

a. Megawatt Capacity and Heat Input Rates

The narrative states that the facility's four tangentially fired steam generating units have a maximum continuous heat input of between 9494 and 9874 million British Thermal Units per hour (MMBtu/hr). Narrative at 7. An accompanying chart provides the maximum heat input capacity of each unit, ranging from 9494 MMBtu/hr for Steam Generator Unit 4 ("SG04") to 9874 MMBtu/hr for Steam Generator Unit 2 ("SG02"). The same chart provides a single maximum *continuous* heat input value for each unit of 7740 MMBtu/hr. The Narrative is thus confusing in that it ascribes a range for maximum *continuous* heat input that varies from what is depicted in the chart. Yet another series of heat input values was provided by GPC in 2009 in connection with applications to upgrade the high pressure sections of the steam turbines for each Unit. In those applications, GPC indicated a "design capacity" of each unit ranging from 9,653 MMBtu/hr input (Unit 4) to 10,078 MMBtu/hr input (Unit 2). Those same applications state that the turbine upgrades will allow each unit to "increase its heat input" but do not indicate by how much or from what starting value. See, e.g., SIP Air Permit Application No. 18835 at 4 (March 9, 2009).

Whatever the actual maximum heat inputs of each Unit, they are not stated anywhere in the Draft Permit. It is essential to the integrity of the permit's emissions limitations that the maximum allowable heat inputs be stated clearly in the Title V permit. Heat input values and pollutant emission factors are used to estimate the maximum emissions of pollutants from the Plant. Pollutant emission rates or limits are expressed as pounds per MMBtu (lb/MMBtu) heat input. Thus, both the legal limit on emissions and the amount of pollutants actually emitted change in proportion to the heat input, all other things being equal. Without maximum hourly heat input values, the Draft Permit fails to inform the public of the amount of pollutants the Plant will potentially emit on a short-term basis, and fails to inform as to the quantity of emissions that can be emitted on a short-term basis by each Unit. Stating maximum heat input values in the Narrative is not sufficient because, as the Narrative states, it is provided merely "as an adjunct for the reviewer and to provide information" and "has no legal standing." Narrative at 1. Furthermore, as noted supra, the Narrative itself is confusing on this point.

In addition, neither the Draft Permit nor the Narrative lists the nameplate megawatt ("MW") capacity for each Unit. A basic and central characteristic of any power plant unit is the amount of electricity it is capable of producing in megawatts. Such an important characteristic should be easily identifiable in both the Draft Permit and Narrative issued for public notice.

The Draft Permit should be revised to state the nameplate capacity for each Unit so that interested parties have a basic understanding of the megawatt capacity of this Plant relative to its emission of air pollutants. Because actual, achievable capacity may differ from a Plant's nameplate capacity, the final permit should also include and clearly identify the historic and projected capacities of the Units. Finally, the Draft Permit must also be revised to provide enforceable limits on the maximum hourly heat input for each Unit.

b. Unclear and Incomplete Permit Terms

The Draft Permit purports to be a stand-alone document, stating on its face that it is "subject to and conditioned upon the terms, conditions, limitations, standards, or schedules contained in or specified on the attached **63** pages." Draft Permit cover page (emphasis in original). However, the Narrative – which expressly is for informational purposes only and has "no legal standing" – references the requirements of other key documents that are not contained within the four corners of the Draft Permit. This creates confusion about what in fact constitutes the permit and whether requirements that lie outside the sixty-three pages of the permit are practically and federally enforceable. The permit must incorporate and consolidate all applicable requirements, and the public must have adequate notice of precisely what constitutes the Draft Permit.

For example, the Draft Permit does not provide the facility's Compliance Assurance Monitoring ("CAM") Plan, which is an important part of any Title V permit. There is a requirement that the facility submit an updated CAM Plan within 180 days of the startup of the scrubbers on each Unit (Condition 5.2.18), but the existing CAM Plan itself is not incorporated as part of the Draft Permit. The Narrative adds confusion by referring the reader to the CAM requirements in a prior permit – Permit No. 4911-207-0008-V-01-0 – and the narrative accompanying that permit. Narrative at 18. It is therefore unclear whether the Draft Permit's CAM provisions, as set forth in Conditions 5.2.5 through 5.2.13, comprise the totality of the facility's CAM requirements or whether additional requirements in other documents also apply. Monitoring and reporting requirements are "applicable requirements" within the meaning of Title V of the CAA, and in fact are a central feature of the Title V program. Transparency in the setting and enforcement of those requirements is integral to the purpose of the Title V program. Therefore, the details of the CAM Plan should be provided as part of the permit that is subject to public notice and not merely cross-referenced in a narrative to a prior permit.

Similarly, Condition 7.15.1 of the Draft Permit states that the facility's "CAIR Permit Application, as corrected by the State of Georgia, is attached as part of this permit." Draft Permit at 48. However, no such document is attached to the Draft Permit put out for public notice. The corrected CAIR permit application should be attached to the Draft Permit and to any final permit.

IV. EPD Improperly Determined PSD Applicability for Turbine Upgrades

In 2009, GPC filed applications with EPD for approval to implement steam turbine upgrades for each of the four units at Plant Scherer. Specifically, GPC proposed to replace the high pressure section of the steam turbine of each Unit with "a new, more efficient high pressure section that will allow for increased steam flow." See, e.g., SIP Air Permit Application No. 18835 at 4 (March 10, 2009). According to GPC,

> [t]he purpose of the project is to improve the efficiency of the high pressure section of the turbine (i.e., after the project, the turbine will be able to generate more electricity from the same amount of coal). The project will also increase the turbine's maximum steamflow capacity which will enable the unit to increase heat input as well.

Id.

GPC further explained that the combined effect of increased efficiency and increased maximum steamflow capacity would allow each Unit to increase its maximum generating capacity by 35 MW, helping to offset the parasitic load of pollution controls that would be installed simultaneously – specifically, the scrubber units required to be installed under the multipollutant rule. Id.

On November 16, 2009, EPD issued a Permit Amendment (No. 4911-207-008-V-02-7) authorizing the turbine upgrade on Unit 3. The work was slated to begin construction in October 2010. Id. at 2. On February 23, 2010, EPD issued another Permit Amendment (No. 4911-207-0008-V-02-A) authorizing the turbine upgrades for the remaining steam generating units, SG01, SG02, and SG04. Narrative at 10. Those projects have planned construction dates of January 2012 (Unit 4), April 2013 (Unit 2) and October 2013 (Unit 1).

It is well known that turbine efficiency projects can result in an increase in annual emissions because the projects make the unit more efficient, which ultimately results in the unit being dispatched more often. Further, if the units had more down time for maintenance and/or partial or forced outages before the turbine efficiency upgrade, the turbine efficiency project would allow for greater hours of operation and/or operation at higher capacities post-project. EPA has typically requested significant detail on such projects to determine if they could result in increased emissions as a result of making the unit more efficient (less costly to operate) and thus capable of being dispatched more frequently and/or operated for more hours. EPA has not found that such projects constitute routine maintenance.

GPC has acknowledged that the turbine upgrades will *enable* the Units to increase their heat input, which would result in an emissions increase. More likely, an increase in heat input will be required. This was confirmed by testimony provided to the Maryland Public Service Commission by an expert for the owner of the coal-fired Brandon Shores power plant. The Brandon Shores power plant consists of 2 coal-fired units with a total generating of capacity of 1,370 MW. The proceeding concerned a request by the company, Constellation Power Source Generation, Inc., for a certificate of public convenience and necessity to retrofit pollution controls and conduct other enhancements. As here, a turbine efficiency project was to be conducted concurrent with the installation of air pollution control equipment. According to the testimony of Dori J. Costa, who was employed by and testified on behalf of Constellation Power, the turbine efficiency project, which included an upgrade to the high pressure steam turbine, would require more heat input to the boiler:

> Power block enhancements will include an upgrade of the high pressure steam turbine path components to increase turbine efficiency. The results of this upgrade will improve heat rate and increase generator output at current steam flow. The increased turbine efficiency will result in reduced high-pressure steam turbine exhaust temperature. In order to compensate for the lower temperature, additional enhancements to the boilers will be needed, which include upgrades to the economizers, superheaters, upgrades to related process equipment, as well as requiring an increase in fuel derived heat input to the boilers.

October 23, 2006 Testimony of Dori J. Costa, on behalf of Constellation Power Source Generation, Inc., before the Public Service Commission of Maryland (Case No. 9075), at pp. 6-7 (Ex. 5).

Thus, GPC's planned efficiency upgrades to the high pressure steam turbines will not just enable, but could very well require, additional heat input (i.e., more coal burned) to the boilers as well as boiler changes to increase the high pressure steam turbine exhaust temperature.

According to GPC's applications, the replacement turbines will be supplied by Alstom Power, Inc. As described in Alstom's own literature, turbine efficiency upgrades can accommodate such increases in steam flow as would generate more electricity but also require additional fuel derived heat input to the boiler. Alstom has stated that one of the benefits of steam turbine retrofits is a capacity increase:

> The improved efficiency of a [turbine] retrofit produces additional capacity. It can be further optimized to match the increased steam flow from an uprated boiler ....

Alstom Power Brochure, "Steam Turbine Retrofit, Add Life, Add Power," at 3. (Ex. 6).

Even though GPC stated that the turbine projects "will not involve any physical changes to the boiler," see Application No. 18835 at 3, the reality is that high pressure steam turbine upgrades result in more energy being removed from the steam path, which in turn requires more heating of the steam in the boiler before the steam enters the intermediate pressure and low pressure turbines. More heating of the steam requires more coal to be burned, which in turn produces more emissions. In fact, a filing by Florida Power & Light Company ("FPL") in the Florida Public Service Commission concerning the planned turbine upgrade for Scherer Unit 4 reveals that FPL was motivated to commence the construction before July 1, 2011 in order to avoid New Source Review of Scherer Unit 4 for greenhouse gas emissions. See PSC Order dated October 14, 2010 at 1 (Docket No. 100404-EI) (Ex. 7). This may also explain why GPC submitted its applications so far in advance of the planned construction dates. The concern over triggering NSR review for greenhouse gas emissions arises because the upgraded turbines will be burning more fuel, resulting in increased emissions of CO_2 and other pollutants.

In issuing the Permit Amendments authorizing the turbine upgrades, EPD accepted GPC's analysis that the projects would not result in an emissions increase; that they would instead result in decreased emissions of NO_X, SO_2, sulfuric acid mist (SAM), and PM, and that although there would be increases in CO and VOC emissions, such emissions would be below the applicable significance thresholds of 100 and 40 tons per year, respectively. See, e.g., Narrative for Permit No. 4911-207-0008-V-02-7 at 5. Thus, EPD concluded that the turbine projects will not trigger NSR/PSD for any regulated NSR pollutant emitted by the facility. See, e.g., id.

EPD's analysis appears flawed in the following respects: (1) EPD failed to follow the required two-step procedure for determining whether the projects will result in a "significant emissions increase" and a "significant net emissions increase," effectively collapsing the analysis into a single step that credited decreased emissions from the separate but contemporaneous project of installing pollution control equipment; and (2) EPD improperly determined that decreased emissions resulting from the installation and operation of control equipment under the Multipollutant Rule and Rule (uuu) were creditable.

a. Legal Background

Georgia's SIP adopts the federal PSD regulations set forth at 40 C.F.R., Part 52.21, as amended. See Ga. Comp. R. Regs. r. 391-3-1-.02(7). Under the PSD regulations, a "project" is a major modification triggering NSR review if it causes two types of emissions increases, (1) a significant emissions increase and (2) a significant net emissions increase. 40 C.F.R. § 52.21(a)(2)(iv)(a).

The PSD regulations define a "significant emissions increase" for an NSR pollutant as an increase in emissions that is considered to be significant for that pollutant. 40 C.F.R. § 52.21(b)(40). For SO_2 and NO_X, "significant" is defined as an emissions increase that equals or exceeds 40 tons per year (tpy). 40 C.F.R. § 52.21(b)(23). A "significant net emissions increase is simply a "net emissions increase" that is "significant." Id. Again, "significant" for these pollutants is more than 40 tpy. Id. A "net emissions increase" involves an arithmetic determination of whether a project will result in an emissions increase by adding all the emissions increases that will result from a project and then adding and/or subtracting all contemporaneous, creditable emission increases and emission decreases. The definition of "net emissions increase" includes limitations on the emission reductions that can be credited. 40 C.F.R. § 52.21(b)(3).

The regulations specify a procedure for determining whether a project will result in a "significant emissions increase" and a "significant net emissions increase." 40 C.F.R. § 52.21(a)(2)(iv)*(b)*. To determine whether a "significant emissions increase" from a project will occur, one must use a specific methodology depending on the type of modification that will occur. Id. If the project involves only existing emission units, as is the case here, then one must use the actual-to-projected-actual applicability test. 40 C.F.R. §52.21(a)(2)(iv)*(c)*. Under this test, a significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between projected actual emissions and the baseline actual emissions, for each existing emissions unit, equals or exceeds the significance threshold for that pollutant. Id.

"Baseline actual emissions" are defined in 40 C.F.R. § 52.21(b)(48)(i) and (ii). For an existing electric utility steam generating unit, the term means the average rate, in tons per year, at which the unit actually emitted a regulated NSR pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding the commencement of construction on the project. 40 C.F.R. § 52.21(b)(48)(i). The average rate must include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions; must be adjusted downward to exclude non-compliant emissions; and must not be based on any consecutive 24-month period for which there is inadequate information for determining emissions. 52.21(b)(48)(i) *(a), (b), (d)*.

b. EPD and GPC Improperly Combined Pollution Control Projects with the Turbine Upgrade Project in Determining Whether a Significant Emissions Increase of SO_2 and NO_X Would Occur.

Although GPC's emissions calculations are far from transparent[4], it appears GPC took into account the effect of such other projects as the installation and operation of the SCR and scrubber systems required to be installed under Rule (sss), and the accompanying reductions in SO_2 emissions required under Rule (uuu). Moreover, it appears that any increases associated

[4] For example, the application for the turbine upgrade at Unit 3 clearly states that NO_X emissions estimates are based on "ozone season only operation of the SCR system at 0.07 lb/mmBtu." However, regarding SO_2 emissions, the application states only "CEMS, permit limit," for the method of determination of such emissions, without identifying the permit limit in question. See Form 4.00 dated February 23, 2009. The only conceivable permit limit that could result in a reduction of SO_2 emissions from 19,825.8 tons per year (baseline) to 1,344.6 tpy (projected actual) is the Rule (uuu) limit requiring a 95 percent reduction of such emissions. If another limit is contemplated, the application does not state what it is.

with the turbine projects and the decreases expected from the installation and operation of the pollution control equipment were considered in a single step, with the net result demonstrating a substantial decrease in projected actual NO_X and SO_2 emissions as compared to baseline. This was improper, as the PSD rules do not allow one to take credit for emission reductions in the first step of PSD applicability, i.e., in determining whether a project will result in a "significant emissions increase."

PSD applicability for a pollutant to be emitted by a project requires both a "significant emissions increase" and a "significant net emissions increase." To determine whether the first type of increase will occur, one must first determine the emissions increases that will result from the project in question – i.e., the turbine upgrade. 40 C.F.R. § 52.21(a)(2)(iv)*(c)*. EPA's revisions to the PSD regulations specified a two-step applicability process. When EPA made those revisions, the agency stated "[w]e have revised the definition of major modification to clarify what has always been our policy—that determining whether a major modification has occurred is a two-step process." 67 Fed. Reg. 80190 (December 31, 2002). EPA's policy on this issue states that a modification must first result in a significant emissions increase before one takes into account all contemporaneous emission increases and decreases in determining net emissions increase. EPA's October 1990 New Source Review Workshop Manual also incorporates this policy in determining whether a modification is major. Specifically, Table A-5 of the New Source Review Workshop Manual states as the first step in determining New Source Review applicability:

> Determine the emissions increase **(but not any decreases)** from the proposed project. If increases are significant, proceed; If not, the source [sic] is not subject to review.

October 1990 New Source Review Workshop Manual at A.45 (emphasis added).[5]

Contrary to this approach, GPC and EPD appear to have taken into account the SO_2 and NO_X (as well as PM) decreases expected to result from Rules (sss) and (uuu) concurrently with the emissions increases that seem likely to result from the turbine upgrade projects. By doing so, GPC and EPD have unlawfully and improperly avoided following the rules of determining a net emissions increase. This circumvention of the PSD regulations is incorrect as a matter of law and cannot be allowed.

Instead, GPC and EPD must first, in step 1, determine whether the turbine upgrade projects will result in a significant emissions increase of any NSR pollutant. Such a review should have included the gathering of more information from GPC to determine if emissions

[5] The next page of the NSR Workshop Manual provides an example of how to determine applicability and states with respect to the first step of determining applicability that "only emissions increases expected to result from the proposed project are examined … Emissions decreases associated with a proposed project … are contemporaneous and may be considered along with other contemporaneous emissions changes at the source. However, they are not considered at this point in the analysis …." NSR Workshop Manual at A.46.

might increase from the turbine upgrade projects, such as if the units were projected to be dispatched more often or otherwise will be operating more hours or at higher capacity more often. EPD must, in particular, evaluate whether GPC will operate the Units at a higher heat input rate going forward.[6]

The PSD rules allow for applicability to be determined based on an actual-to-projected-actual analysis. However, in this first step of the analysis, emission decreases associated with pollution control projects and accompanying limits cannot be considered. Such emission reductions can only be considered in the second step of applicability – i.e., in determining net emissions at the source – and only if the reductions are contemporaneous and otherwise creditable. See 40 C.F.R. § 52.21(b)(3). The failure by GPC and EPD to determine separately whether a significant increase in emissions of any NSR pollutant will result from the turbine upgrades was contrary to the PSD regulations as incorporated into Georgia's SIP.

c. GPC and EPD Failed to Conduct a Proper Analysis of Whether a Significant Net Emissions Increase of SO_2 or NO_X would occur as a Result of the Turbine Upgrades.

After the increase in actual emissions from a project is determined to be significant, the next step in determining net emissions increase is to evaluate all other contemporaneous emissions increases and decreases at the source that are contemporaneous with the change. The contemporaneous period is defined in the regulations as beginning on the date five years before construction commences on a change and ending on the date the increase from the change occurs. 40 C.F.R. § 52.21(b)(3)(ii).

Further, it must be determined whether any contemporaneous decrease in actual emissions is "creditable." A decrease in actual emissions is creditable only to the extent that, among other things, "[i]t is enforceable as a practical matter at and after the time that actual construction on the particular change begins." 40 C.F.R. § 52.21(b)(3)(vi)*(b)*.

If indeed GPC took credit for decreases associated with the Multipollutant Rule and Rule (uuu) in determining net emissions, this was improper for at least two reasons. First, the reductions are not enforceable as a practical matter. As discussed further in Sections I and V.d.iv of these Comments, neither rule is enforceable during periods of allowable excess emissions (broadly defined periods of startup, shutdown and malfunction), and there is no requirement for

[6] Commenters note that the design capacity of each Unit set forth in the project applications is higher than the values provided in Narrative accompanying the Title V Permit Renewal for the maximum continuous heat input for each Unit. For example, the design capacity of SG01 is stated as 10,052 lb/MMBtu versus a maximum continuous heat input of 7740 lb/MMBtu that is stated in the Title V Permit Renewal Narrative along with a maximum heat input capacity of 9860 lb/MMBtu for that Unit. *Compare* SIP Application No. 19316 at Form 2.01 (Nov. 18, 2009) to Narrative at 7.

continuous monitoring during such episodes. Thus, the rules are not practically enforceable and cannot be taken as credit against increased emissions that result from the turbine upgrades. Second, it is not clear that such limits were or will be in effect "at and after the time that actual construction on the particular change begins." To use the planned turbine upgrade at Unit 3 as an example, construction was scheduled to commence in October 2010; in contrast, the requirements of Rule (sss) and (uuu) for that Unit would not take effect until July 1, 2011. As a result, the decreases in emissions projected from those rules taking effect are not properly creditable.

The above analysis focuses on PSD applicability. Because Plant Scherer is located in an area that is nonattainment for ozone and $PM_{2.5}$, the required applicability review for NO_X, an ozone precursor, and for PM and SO_2, which contribute to $PM_{2.5}$ emissions, is properly termed "new source nonattainment" review. However, the analysis regarding whether a project constitutes a "major modification" triggering NSR review and whether the project results in a "net emissions increase," including whether decreases in actual emissions are creditable, is the same as set forth above. See Ga. Comp. R. & Regs. r. 391-3-1-.01 (incorporating by reference 40 C.F.R. § 51.165(a)(1)(v) (defining "major modification") and 40 C.F.R. § 51.165(a)(1)(vi) (defining "net emissions increase")). The difference is that under PSD review, a net emissions increase is permissible so long as it does not consume the available PSD increment or otherwise threaten compliance with the NAAQS. In contrast, in a nonattainment area, net emissions increases must generally be "offset" by emission reductions that are "surplus, permanent, quantifiable, and federally enforceable." 40 C.F.R. § 51.165(a)(3)(ii)(C)*(1)(i)*. And because Monroe County is considered among the areas contributing to ambient air levels of ozone in the metropolitan Atlanta Ozone Nonattainment Area, NO_X offsets are required at a minimum ratio of 1.1 to 1. Ga. Comp. R. & Regs. r. 391-3-1-.03(8)(c)15(iv). Thus, when an appropriate NSR analysis is performed, in which no credit is given for emission reductions that cannot be considered practically enforceable, offsets of increased NO_X, SO_2 and PM emissions may well be required, perhaps warranting significant tightening of the permit's limits for those pollutants.

The problem is that neither a PSD nor a nonattainment NSR review has been appropriately and completely performed regarding the proposed turbine upgrades. Until such review occurs, the Plant is in violation of applicable NSR regulations.

All sources subject to Title V must have a permit to operate that "assures compliance by the source with all applicable requirements." See 40 C.F.R. § 70.1(b); Clean Air Act § 504(a), 42 U.S.C. § 7661c. To meet this requirement, every Title V permit application must provide "a description of all applicable requirements" and must disclose any violations at the facility. See 42 U.S.C. § 7661b(b); 40 C.F.R. §§ 70.5(c)(4)(I), (5), (8).

Georgia and federal law define "applicable requirements" to include "any standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under title I of the Act that implements the relevant requirements of the Act, including any revisions to that plan promulgated in 40 CFR part 52." 40 C.F.R. § 70.2 (incorporated by reference by Ga. Comp. R. & Regs. r. 391-3-1-.03(10)(a)4). This definition encompasses the requirement for new and modified major stationary sources to obtain PSD permits that fully comply with all applicable PSD requirements under the Act and the Georgia SIP, including the requirements to apply best available control technology (BACT) and to perform air quality demonstrations. *See generally* CAA 110(a)(2)(C), 160-69, 173; 40 C.F.R. §§52.21 et seq.

For any applicable requirements, including PSD requirements and other preconstruction requirements, for which the source is not in compliance at the time of permit issuance, the source's application must provide a narrative description of how the source intends to come into compliance with the requirements. 42 U.S.C. § 7661b(b); 40 C.F.R. § 70.5(c)(8) – (9). The application must further propose a compliance schedule for any applicable requirements for which the source is not in compliance. 40 C.F.R. § 70.5(c)(8)(iii). If any statements in the application are incorrect, or if the application omits relevant facts, the applicant has an ongoing duty to supplement and correct the application. Ga. Comp. R. & Regs. r. 391-3-1-.03(10)(c)5; 40 C.F.R. § 70.5(b).

As detailed supra, EPD has failed adequately to evaluate GPC's compliance with PSD requirements in connection with the steam turbine upgrades, and it is probable that PSD violations are ongoing. Therefore, the proposed Title V permit cannot be issued because a compliance schedule to address probable ongoing PSD violations has not been included in the Draft Permit.

V. Emission Standards and Compliance

a. Heat Inputs

As explained above, supra Part III.a., an increase in hourly heat input rate increases pollutant emissions from the Units at the Plant, and effectively increases their lb/MMBtu emission limitations. It is important that these values not only be included in the permit, but also that they be made enforceable limits. Without an enforceable maximum hourly heat input limit, each Unit is unconstrained as to its maximum short-term emissions.

Maximum short-term pollutant emissions from the Plant can form the basis for air quality planning, i.e., an assessment of air quality impacts from this source, and establishing emissions limitations necessary to achieve and maintain compliance with air quality standards. A higher heat input may require more stringent lb/MMBtu emission limitations, control efficiency requirements or operational conditions in order to address the Plant's contribution to nonattainment of the ozone and $PM_{2.5}$ NAAQS, and assure compliance with other air quality standards such as the new short-term one-hour NAAQS for NO_X and SO_2.

Finally, without enforceable maximum hourly heat input limits, the public and affected states have no opportunity to review and comment on a plant with a higher heat input (and thus higher actual emissions and effectively higher total emissions limitations) than what is identified in the Draft Permit. The rated heat inputs represented by GPC in its permit application and relied upon by EPD in issuing any permits for the Plant are applicable requirements (as are all data and assertions in the application) and must be stated as such and included in the permit as conditions that are subject to monitoring, record-keeping and reporting requirements adequate to demonstrate compliance.

b. Fuel Flexibility

The Draft Permit allows the Plant to burn almost any type of fuel, without regard to the pollutant characteristics of the fuels, and without limiting the percentage of non-coal fuels used. Although the Plant's units "primarily burn coal," Draft Permit at 1, it is permitted to blend the coal with sawdust and biomass, or fire used oil and coal-derived synthetic fuel. Draft Permit at 4. The Plant is also permitted to burn No. 2 fuel oil, biodiesel, or biodiesel blends for startup and shutdown, and "to assist in achieving peak load, and flame stabilization." Id. The addition to or replacement of coal with any of the other permitted fuels could significantly change the pollutant profile of this plant. Further, the fuel characteristics of different coals such as heat value and the content of pollutants such as mercury and sulfur also affect the type and quantity of pollutants emitted. See, e.g., United States Geological Survey, Mercury in Coal, http://energy.er.usgs.gov/health_environment/mercury/mercury_coal.html (last accessed, October 21, 2011). Thus, the use of non-coal fuels must be more specifically defined and strictly limited in the final permit. The chemical characteristics of all permitted fuels, including coal, should be monitored and limited.

The only restrictions placed on the use of these alternative fuels are on coal-derived synthetic fuel and used oil. The former has percentage limits on the mercury and binder content, and the latter may not be burned during startup or shutdown. There are no limits on the quantity or characteristics of any of these fuels, and no limits on fuel characteristics but for those on mercury and binder in coal-derived synthetic fuel. The definition of biomass is completely without limit. "Biomass" has been defined to include everything from wood chips to municipal solid waste, making a specific definition particularly important for this fuel category. Indeed, if the Plant burns waste, it should be subject to additional regulations for waste incinerators. As drafted, the permit would allow GPC to switch fuels. Because the Draft Permit does not limit the maximum hourly heat input rate, this could drastically affect the Plant's actual emissions, even when burning fuels that otherwise meet the permit's lb/MMBtu specifications. As to the use of No. 2 fuel oil, biodiesel, and biodiesel blends, the operational conditions during which these fuels may be used are much too vaguely defined.

The final permit should specifically limit the use of non-coal fuels, because the potential change in fuels covered by this permit would significantly change the emissions contemplated by EPD in issuing this permit. EPD and GPC should perform a thorough and public analysis of the type and quantity of pollutants that may be emitted by all permitted fuels in all potential combinations. Fuel characteristics such as heat input, mercury content, and sulfur content should be limited and monitored. EPD should also require the permittee to monitor and report the types of fuels actually used at the Plant, including the quantities burned and the pollutant characteristics of each. The permit must also explain what is meant by "achieving peak load" and "flame stabilization" in terms that meaningfully limit when No. 2 fuel oil and biodiesels may be used. Startup and shutdown should also be more strictly defined, as described in Section VI infra.

c. Particulate Matter

i. The PM Limit Should be Significantly Lowered in Order to Abate the Facility's Contribution to Nonattainment of the $PM_{2.5}$ NAAQS.

Particulate matter ("PM"), also called particle pollution, is a complex mixture of extremely small particles and liquid droplets in the air. When breathed in, these particles can reach the deepest regions of the lungs. Exposure to particle pollution is linked to a variety of significant health problems, ranging from aggravated asthma to premature death in people with heart and lung disease. Particle pollution is also the main cause of visibility impairment in the nation's cities and national parks. The area surrounding Plant Scherer has been designated "Nonattainment" for the 1997 NAAQS for fine particle pollution, or $PM_{2.5}$. Plant Scherer's PM emissions contribute significantly to the $PM_{2.5}$ nonattainment status of the area.

Georgia regulations provide:

> No person owning, leasing, or controlling operation of any air contaminant sources shall willfully, negligently or through failure to provide necessary equipment or facilities or to take necessary precautions, cause, permit, or allow the emission from said air contamination source or sources of such quantities of air contaminants as will cause, or tend to cause, by themselves or in conjunction with other air contaminants a condition of air pollution in quantities or characteristics or of a duration which is injurious or which unreasonably interferes with the enjoyment of life or use of property in such area of the State as is affected thereby. Complying with any of the other sections of these rules and

> regulations or any subdivision thereof, shall in no way exempt a person from this provision.

Ga. Comp. R. & Regs. r. 391-3-1-.02(2)(a)1. This facility's contribution to a NAAQS violation for a pollutant known to have serious effects on human health subjects it to particular scrutiny under the above provision.

The Draft Permit imposes a limit on PM emissions from the four steam-generating units of 0.10 lb/MMBtu. Draft Permit at 5. This limit is derived from the New Source Performance Standards governing fossil-fuel fired steam generators for which construction was commenced after August 17, 1971. See 40 C.F.R. § 60.42(a)(1). EPD is free to impose a more stringent limit, and must do so in order to abate the facility's contribution to Nonattainment for the $PM_{2.5}$ NAAQS established 15 years ago. A review of compliance records shows that the facility routinely emits well below the permitted limit – for example, in January 2010, the facility's PM emissions were 4% of the allowable limit[7] – and yet the surrounding area remains in Nonattainment. The 0.10 lb/MMBtu limit gives the Plant an enormous compliance margin, and no incentive to operate its ESPs and baghouses efficiently or otherwise minimize emissions. A more stringent limit is needed to reflect the much lower emission rates that the facility is already capable of achieving and to give it an incentive to minimize emissions further.

ii. Coarse and Fine Particle Pollution Should be Limited and Monitored Separately.

The term "particulate matter," or "PM," includes two different types of pollutants: fine particle pollution, or $PM_{2.5}$, and coarse particle pollution, or PM_{10}. If the only methods used to test PM levels are EPA Methods 5 and 17, Draft Permit at 13, the PM limit as described fails to provide a limit specific to $PM_{2.5}$. See 40 C.F.R. § 51 Appendix M (Recommended Test Methods for State Implementation Plans). Thus, the PM limit applies to total suspended particulate matter, and only its filterable component. This PM limit is inadequate. Both forms of PM have been linked to numerous deleterious health effects, including decreased lung function, aggravated asthma, chronic bronchitis, irregular heartbeat, heart attacks, and premature death. However, PM_{10} and $PM_{2.5}$ differ significantly, and separate NAAQS exist for each pollutant. Both PM_{10} and $PM_{2.5}$ should be clearly regulated in the Draft Permit. This facility's contribution to Nonattainment of the $PM_{2.5}$ NAAQS makes separate regulation of this pollutant even more important.

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[7] See Particulate Matter Testing Deferral Request for 2011 (Feb. 23, 2011).

PM_{10} and $PM_{2.5}$ are distinct air pollutants that do not share the same physical or behavioral characteristics. See, e.g., EPA, "Clean Air Fine Particle Implementation Rule" 72 Fed. Reg. 20586, 20599 (April 25, 2007) ("PM[2.5] also differs from PM[10] in terms of atmospheric dispersion characteristics, chemical composition, and contribution from regional transport."). PM_{10} and $PM_{2.5}$ pose different kinds and levels of risk to human health. Because of its extremely small size, $PM_{2.5}$ can penetrate deep into the lungs, enter the blood stream, and cross the blood-brain barrier. As a result, $PM_{2.5}$ pollution causes more frequent and severe adverse health effects than PM_{10}. EPA, "National Ambient Air Quality Standards for Particulate Matter," 62 Fed. Reg. 38652, 38665 (July 18, 1997). EPA has recognized a significant correlation between elevated $PM_{2.5}$ levels and premature mortality. See, e.g., EPA, "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$)," 73 Fed. Reg. 28321, 28324 (May 16, 2008). Older adults, people with heart and lung disease, and children are particularly sensitive to $PM_{2.5}$ exposure. Id.

Finally, and most importantly, because of their different physical and behavioral characteristics, PM_{10} and $PM_{2.5}$ are not effectively treated with the same pollution controls. In fact, EPA has recognized that PM_{10} controls do not effectively control $PM_{2.5}$: "In contrast to PM[10], EPA anticipates that achieving the NAAQS for PM[2.5] will generally require States to evaluate different sources for controls, to consider controls of one or more precursors in addition to direct PM emissions, and to adopt different control strategies." 72 Fed. Reg. 20586, 20589; see also 62 Fed. Reg. at 38666.

EPA has confirmed that any technical impediments to the separate regulation of $PM_{2.5}$ have been resolved. 73 Fed. Reg. at 28340 ("With this final action [establishing NSR regulations for $PM_{2.5}$ and eliminating the PM_{10} Surrogacy Policy] and technical developments in the interim, these difficulties have largely been resolved"). Moreover, EPA announced in the final $PM_{2.5}$ implementation rule that for Title V permits, "as of the promulgation of this final rule, the EPA will no longer accept the use of PM_{10} emissions information as a surrogate for $PM_{2.5}$ emissions information given that both pollutants are regulated by a National Ambient Air Quality Standard and therefore are considered regulated air pollutants." Clean Air Fine Particle Implementation Rule; Final Rule, 72 Fed. Reg. 20586, 20660 (April 25, 2007) (footnotes omitted). EPA explained its decision as follows:

> Under the Title V regulations, sources have an obligation to include in their Title V permit applications all emissions for which the source is major and all emissions of regulated air pollutants. The definition of regulated air pollutant in 40 CFR 70.2 includes any pollutant for which a NAAQS has been promulgated, which would include both PM[10] and PM[2.5]. To date, some permitted entities have been using PM[10] emissions as a surrogate for PM[2.5] emissions. Upon promulgation

> of this rule, EPA will no longer accept the use of PM[10] as a surrogate for PM[2.5]. Thus, ***sources will be required to include their PM[2.5] emissions in their Title V permit applications, in any corrections or supplements to these applications, and in applications submitted upon modification and renewal.*** *See* 40 CFR 70.5(c)(3)(i), 70.5(b), and 70.7(a)(1)(i); 40 CFR 71.5(c)(3)(i), 71.5(b), and 71.7(a)(1)(i).

Id. (emphasis added). The EPA has thus clearly stated that this Draft Permit is deficient and must be revised to include emission limits and monitoring specifically for $PM_{2.5}$.

iii. The Frequency of PM Testing Must Be Increased.

Compliance with the facility's PM limit is demonstrated via a stack test following 8760 operating hours. Draft Permit at 14, Condition 4.2.1. However, the facility is allowed to request that annual testing be deferred for an additional 8760 operating hours if the results of the last test are less than half the applicable emissions standard, i.e., Condition 3.4.1. Id. As a result, the Plant may only conduct stack testing for PM emissions once every two years. A review of the permitting record reveals that the facility has frequently made, and EPD has routinely granted, such testing deferral requests.

The expected operational variability of these units can significantly affect ESP control efficiency and thus, resulting emissions. Moreover, the facility is not required to operate baghouses on all units until the end of 2014, and even then, monitoring sufficient to detect excess emissions will remain necessary to demonstrate compliance. Federal regulations make clear that monitoring and reporting requirements must, to the extent possible, match the time period over which an emission limitation is measured. Under 40 C.F.R. § 70.6(a)(3)(i)(A), permitting authorities must ensure that Title V permits contain all applicable monitoring requirements. If an applicable CAA requirement contains no periodic monitoring, permitting authorities must add "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." 40 C.F.R. § 70.6(a)(3)(i)(B) (LexisNexis 2011). On the other hand, if there is some periodic monitoring in the permit, but that monitoring is not sufficient to assure compliance with permit terms and conditions, permitting authorities must supplement monitoring to assure compliance. 40 C.F.R. § 70.6(c)(1) (LexisNexis 2011). In all cases, the rationale for the selected monitoring requirements must be clear and documented in the permit record. 40 C.F.R. § 70.7(a)(5) (LexisNexis 2011); Ga. Comp. R. & Regs. r. 391-3-1-.03(10)(a)(2) (LexisNexis 2010) (requiring that Title V permits "assure compliance with all applicable requirements"), and (d)(1) (incorporating 40 C.F.R. Part 70.6(a) and 40 C.F.R. 70.7(f)).

The Draft Permit's infrequent and intermittent compliance testing requirements will not assure or demonstrate compliance with PM limitations, which are applicable on a continuous basis. Nor will they adequately address this facility's contribution to NAAQS violations and potential NAAQS violations that are based on one-hour averages. Particularly because this facility significantly contributes to nonattainment of the $PM_{2.5}$ NAAQS, monitoring equipment sufficient to provide a complete and accurate picture of the Plant's PM emissions should be installed and maintained. The resulting data should then be submitted to the agency and available to the public.

The Draft Permit should be revised to mandate the installation and use of a continuous emissions monitoring system (CEMS) for PM in lieu of the requirements of draft condition 4.2.1. PM_{10} CEMS are common and have been readily available on a commercial scale for many years. EPA, Current Knowledge of Particulate Matter (PM) Continuous Emissions Monitoring (Sept. 2000), available at http://www.epa.gov/ttnemc01/cem/pmcemsknowfinalrep.pdf. PM CEMS should be installed "to assure compliance with the permit terms and conditions" as required by Title V of the Clean Air Act. 42 U.S.C. § 7661c(c) (LexisNexis 2011).

d. NO_X and SO_2

i. The Draft Permit Must be Revised to Incorporate Revisions to Rules (sss) and (uuu)

The Draft Permit incorporates the requirements of Georgia's Multipollutant Rule, Ga. Comp. Rules & Regs. r. 391-3-1-.02(2)(sss), at Condition 3.4.14. In accordance with Rule (sss), the Plant is required to operate its Units with selective catalytic reduction, flue gas desulfurization, sorbent injection and a baghouse by the effective dates stated in the Rule.

In June 2011, Rule (sss) was amended to advance the compliance date for Scherer Unit 3 ("SG03"). Specifically, the compliance date for SG03 was moved from December 31, 2011 to July 1, 2011. The effective date in the first sentence of Condition 3.4.14 must be revised to reflect that change.

A similar change was made to companion Rule (uuu). The deadline for SG03 to achieve a 95 percent reduction in SO_2 emissions as a result of the installation and operation of new pollution control equipment was moved from January 1, 2012 to July 1, 2011. See Ga. Comp. Rules & Regs. r. 391-3-1-.02(uuu)2(ii). Thus, the effective date in the first sentence of Condition 3.4.15 in the Draft Permit must be revised to reflect that change.

Condition 4.2.4 must also be changed to reflect the revised the deadlines applicable to Scherer Unit 3. Condition 4.2.4 requires initial and ongoing (30-day rolling) performance tests for SO_2 reductions required under Rule (uuu). Draft Permit at 15; Narrative at 16. As currently written, Condition 4.2.4 requires the initial performance test on unit SG03 to occur on January 1, 2012 consistent with the original deadline for equipping that unit with an FGD device. That date should be changed to July 1, 2011 to make it consistent with the June 2011 revisions to Rule (uuu).

ii. The Draft Permit Must be Revised to Include Cross-State Air Pollution Rule Requirements.

The Draft Permit contains requirements under the Clean Air Interstate Rule ("CAIR") at Condition 7.15. Draft Permit at 48-49. The requirements include annual NO_X allowance allocations for the Plant's four units for 2011 through 2014.

On July 7, 2011, the EPA released the final Cross-State Air Pollution Rule ("CSAPR") as a replacement to CAIR. The final rule applies to 27 states, including Georgia. Like CAIR, the CSAPR establishes an annual allowance trading program for SO_2 and NO_X to reduce transport of fine particulate matter and a separate ozone season NO_X allowance trading program to reduce ground-level ozone. CSAPR will replace CAIR and all of its compliance requirements. CAIR annual and seasonal NO_X allowances will have no value for CSAPR compliance purposes, although the Acid Rain SO_2 program will continue as a separate program. Compliance with the annual reduction requirements will be required beginning January 1, 2012, with further reductions taking effect on January 1, 2014. The ozone season NO_X reduction requirements will take effect on May 1, 2012, with further required reductions beginning May 1, 2014.

The final rule is structured as a Federal Implementation Plan (FIP). EPA has given Plant Scherer the following allocations under the final rule:

	SO2 Allocation 2012 (tons)	SO2 Allocation 2012 (tons)	NOx Annual Allocation 2012 (tons)	NOx Annual Allocation 2014 (tons)	NOx OS Allocation 2012 (tons)	NOx OS Allocation 2014 (tons)
Unit SG01	11,465	6,864	4,336	2,800	2,395	1,409
Unit SG02	11,782	7,054	4,456	2,877	2,580	1,427
Unit SG03	11,372	6,809	4,301	2,777	2,081	1,443
Unit SG04	11,621	6,958	4,396	2,838	2,215	1,474

The above allocations give the facility both an SO_2 and an ozone season NO_X allocation, whereas the CAIR provisions of the Draft Permit provide allocations only for annual NO_X. Draft Permit at 48-49.

CAA 504(a) requires each Title V permit to "assure compliance with applicable requirements of this chapter, including the requirements of the applicable implementation plan [SIP]." 40 C.F.R. § 70.2 defines "applicable requirements" as including "requirements that have been promulgated or approved by EPA through rulemaking at the time of issuance but have future effective compliance dates." As final applicable requirements that will become effective during the permit's term, Plant Scherer's CSAPR allowance allocations must be incorporated into the Draft Permit. Further, the Draft Permit should be revised to indicate that the CSAPR requirements will supplant CAIR as of January 1, 2012.

iii. The Draft Permit's SO_2 Monitoring and Compliance Provisions Must be Revised to be Consistent with the new 1-hr SO_2 NAAQS

On June 2, 2010, the EPA finalized a new one-hour primary NAAQS for SO_2. The final standard, which was set at 75 parts per billion (ppb), replaces two primary standards of 140 ppb, measured over 24 hours, and 30 ppb, measured over one year. In revising the limit to a one-hour standard, EPA cited significant health benefits, particularly for at-risk populations. SO_2 is a known precursor of fine particle pollution. As noted supra, the area around Plant Scherer is nonattainment for the $PM_{2.5}$ NAAQS.

The Draft Permit sets an SO_2 limit of 1.2 lb/MMBtu heat input. Condition 3.3.4. It requires the use of CEMS to monitor SO_2 emissions, and the calculation of a 3-hour rolling average emission rate in lb/MMBtu. Condition 5.2.4. While the Draft Permit nominally requires CEMS operation during all periods of operation, Condition 5.2.21, it also appears to exempt such operation during periods of startup, shutdown and malfunction, as discussed further in Section V.d.iv infra. Further, the Draft Permit allows the facility to refrain from obtaining SO_2 emission data for as much as 25 percent of all operating hours of each successive boiler operating days. Condition 5.2.22. The Draft Permit requires quarterly reporting, as an excess emission, of any 3-hour average SO_2 emission rate, as measured by CEMS, that exceeds 1.2 MMBtu lb/MMBtu heat input. Conditions 6.1.4, 6.1.7.a.v.

Regarding the 95% reduction of SO_2 emissions required under the provisions incorporating Rule (uuu)'s requirements, the Draft Permit requires an "initial performance test" for the first 30 successive boiler operating days following the applicable deadlines for each Unit. Condition 4.2.4.a. After the initial performance demonstration, the Draft Permit requires a separate performance test at the end of each operating day and the calculation of a new 30-day percent reduction calculated to demonstrate compliance. Id. The Draft Permit does not specify what constitutes a "performance test" for purposes of this provision; presumably the demonstration is made via SO_2 CEMS. Compliance with the percent reduction requirement is demonstrated based on a 30-day average. Condition 6.2.14.

The Draft Permit's SO_2 monitoring and compliance provisions are insufficient in light of the new one-hour SO_2 NAAQS. Because Plant Scherer is a large single source of SO_2 emissions, its emissions alone could violate the one-hour NAAQS. For this reason, the Draft Permit must be revised to include provisions that conform to the new standard. First, the SO_2 limit should be substantially lowered to reflect the limits the facility is capable of achieving on a continuous basis both before and following the planned scrubber installations.[8] Second, compliance with the limit must be required to be demonstrated on an hourly basis. Because the Draft Permit already requires CEMS, there is no technical obstacle to requiring the facility to monitor and report its SO_2 emissions on an hourly basis. Unless such revisions are made, the final permit will lack an SO_2 limit that is designed to achieve and maintain the SO_2 NAAQS, and will lack a compliance provision designed to show that the limit is being met over the same averaging period as the prevailing air quality standard.

iv. The Permit Should Clearly Require SO_2 CEMS Operation During All Periods of Operation except CEMS Breakdown and Repair.

The Draft Permit properly requires that SO_2 CEMS be operated during all periods of operation, including periods of startup, shutdown, malfunction or emergency. Draft Permit at 25 Condition 5.2.21. However, it addition to exempting "CEMS breakdowns, repairs, calibration checks, and zero and span adjustments," Condition 5.2.21 also exempts "any period allowed under Condition 3.4.19." The latter condition, in turn, exempts the Plant's units from the 95% SO_2 reduction requirements of Rule (uuu) during periods of "black starts" and scheduled or preventive maintenance as well as during periods of startup, shutdown or malfunction provided such episodes are consistent with the air quality rule governing allowable "excess emissions," Rule 391-3-1-.02(2)(a)7. Draft Permit at 11.

Thus, while appearing at first blush to require the operation of SO_2 CEMS during periods of startup, shutdown, or malfunction, the Draft Permit appears ultimately to eliminate any such requirement. At best, the language in Condition 5.2.21 referencing Condition 3.4.19 is confusing and should be eliminated. The CEMS data are used to demonstrate compliance with the permit's

[8] A review of the facility's recent compliance records reveals that Plant Scherer routinely performs better than the 1.2 lb/MMBtu SO_2 limit in the Draft Permit. See, e.g., SO2 Report for the Period 01/01/2011 to 03/31/11 (showing emission rates ranging from 0.52 to 0.77 lb/MMBtu). It appears these emission rates have resulted from the Plant's decision to burn low sulfur PRB coal. Once scrubbers are installed on all Units as required under the Multipollutant Rule, the facility will be capable of achieving even lower SO_2 emissions, even when burning higher sulfur coal.

SO_2 limit of 1.2 lb/MMBtu. See Draft Permit at 5, 17-18, Conditions 3.3.4, 5.2.4, and 6.1.7a.v. Under CAA Section 302(k), an emission limitation is one that "limits the quantity, rate, or concentration of emissions of air pollutants **on a continuous basis**, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction ..." The permit's SO_2 emissions limitation is meaningful and enforceable only to the extent that compliance with it can be demonstrated on a continuous basis. A clear requirement to operate SO_2 CEMS during all periods except CEMS breakdown and repair is necessary to "assure compliance with the terms and conditions of the permit." 40 C.F.R. § 70.6(c)(1).

VI. Excess Emissions

The Draft Permit contains two conditions covering excess emissions: one covering emergencies (Condition 8.13) and the other covering excess emissions resulting from startup, shutdown or malfunction (Condition 8.14.4). The former is modeled virtually verbatim after 40 C.F.R. § 70.6(g) and therefore appears legally sufficient. The latter provision, however, is flawed in multiple ways and requires significant revision.

a. Condition 8.14.4 Should Not Include an Affirmative Defense

The Draft Permit exempts the Units from emissions limitations during periods of startup, shutdown, and malfunction. Condition 8.14.4 provides the facility with an affirmative defense against enforcement if it can meet certain showings – although unlike the condition governing excess emissions due to emergency (Condition 8.13), it does not use the term "affirmative defense" or even provide that the facility has the burden of establishing the criteria set out in subparagraphs (i) through (iii). Nevertheless, the condition functions like an affirmative defense provision because it allows GPC to escape enforcement under certain circumstances. Specifically, it provides that "excess emissions resulting from startup, shutdown, or malfunction of any source which occur though ordinary diligence is employed **shall be allowed**" provided three criteria are met, namely that:

i. The best operational practices to minimize emissions are adhered to;

ii. All associated air pollution control equipment is operated in a manner consistent with good air pollution control practice for minimizing emissions; and

iii. The duration of excess emissions is minimized.

In contrast, "[e]xcess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may be reasonably be prevented during startup, shutdown or malfunction are prohibited and are violations of Chapter 391-3-1 of the Georgia Rules for Air Quality Control."

EPA has issued several guidance documents regarding excess emissions provisions.[9] EPA has repeatedly stressed that where a single source has the potential to cause an exceedance of the NAAQS or PSD increments – as the agency has noted is often the case with SO_2 emissions from coal-fired units like those at the Plant – preordaining an affirmative defense is not sufficient to protect public health and the environment. Plant Scherer is a single major source of SO_2 emissions and also of PM in an area that is not in attainment with the 1997 $PM_{2.5}$ NAAQS. In such circumstances, EPA has stated that the only appropriate means of dealing with excess emissions during malfunction, startup and shutdown episodes is by responsibly exercising enforcement discretion rather than by prospectively establishing a blanket exemption.

Even though Condition 8.14.4 tracks the language of the state rule verbatim, and the state rule has been approved as part of the SIP, EPD is not obligated to include such language in the Draft Permit and must not do so for Plant Scherer. For the reasons noted by EPA, Plant Scherer is not the type of facility that can be afforded the benefit of an affirmative defense for excess emissions occurring during startup, shutdown or malfunction. Instead, an enforcement discretion approach is warranted, whereby EPD can refrain, on a case-by-case basis, from imposing penalties for sudden and unavoidable malfunctions caused by circumstances entirely beyond the control of the owner or operator. For this reason, Condition 8.14.4 must be stricken from the Draft Permit. Any excess emissions that occur due to startup, shutdown or malfunction, and which are alleged by the source to have been unavoidable, must be handled through an enforcement discretion approach.

b. If an Affirmative Defense is Retained, It Must be Revised to State that All Excess Emissions Are Violations and to Retain the Availability of Injunctive Relief.

EPA has repeatedly made it clear that because excess emissions can aggravate air quality so as to prevent attainment or interfere with maintenance of the ambient air quality standards, it views **all** excess emissions as violations of the applicable emissions limitation. While EPA has recognized that the state or EPA can exercise "enforcement discretion" to refrain from taking enforcement action where the excess emissions result from sudden and unavoidable malfunctions

[9] *See generally* EPA memo entitled, "State Implementation Plans: Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown," by Steven A. Herman dated September 20, 1999; EPA Memo entitled "Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions," by Kathleen M. Bennett dated February 15, 1983; EPA memo entitled "Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions," by Kathleen M. Bennett, dated September 28, 1982.

caused by circumstances entirely beyond the owner or operator's control, the excess emissions remain violations subject to enforcement action. The state can excuse the source from penalties if the source can demonstrate that it meets certain objective criteria; however, the state cannot provide that the excess emissions are not violations. Moreover, the state cannot exempt the source from actions for injunctive relief.

As currently written, Condition 8.14.4 violates both prohibitions. It declares that excess emissions "shall be allowed" – i.e., are not violations – provided that the criteria in subparagraphs (i), (ii) and (iii) of paragraph (a) are met. This is improper, as EPA has made it clear that all excess emissions are violations of the applicable emission limitation, and must be treated as such even in those circumstances where it is appropriate to allow a source an opportunity to present an affirmative defense.

In addition, Condition 8.14.4 appears to improperly preclude injunctive relief. In declaring that under certain circumstances excess emissions from startup, shutdown, or malfunction "shall be allowed," the condition makes no distinction between penalties and injunctive relief: any and all available remedies appear to be precluded. EPA has made it clear that an acceptable affirmative defense provision may only apply to actions for penalties but not to actions for injunctive relief. However, by failing to make any distinction between actions for civil penalties and actions for injunctive relief, Condition 8.14.4 improperly provides a defense against the latter form of enforcement action. This is an inappropriate barrier to enforcement by citizens or EPA.

Therefore, if Condition 8.14.4 is retained in the Permit, it must be revised to state that any excess emissions due to startup, shutdown and malfunction are violations of the Georgia Air Quality Act and federal Clean Air Act. Further, it must be revised to state that any affirmative defense provisions apply only to actions for penalties and not to actions for injunctive relief.

c. If an Affirmative Defense is Retained, It must be Revised to Provide Objective Criteria that Will Allow for Practical Enforceability.

i. Vague and undefined terms must be replaced with specific and objective operational requirements.

The Clean Air Act expressly defines the term "emission limitation" as a limitation on emissions of air pollutants "on a continuous basis." 42 U.S. C. § 7602(k). For affirmative defense for excess emissions occurring during startup, shutdown or malfunction to be valid, the permitting authority must demonstrate that any exemptions from emission limitations are unavoidable and ensure that such exemptions are minimized. To establish a work practice standard as an alternative limit during exempt periods, the permitting authority must determine that technological or economic limitations on the application of a measurement methodology to a particular unit would make the imposition of an emissions standard infeasible during such periods. See, e.g., 40 C.F.R. § 51.166(b)(12) (limiting the exemption from BACT emissions limits for startup, shutdown and malfunction). EPD has done no such analysis to justify the exemptions contained in the permit. It has also failed to provide specific and limiting definitions for these exempt periods so that they only apply when "the imposition of an emissions standard [is] infeasible."

Condition 8.1.1 of the Draft Permit states that "[t]erms not otherwise defined in the Permit shall have the meaning assigned to such terms in the referenced regulation." However, the regulation referenced by Condition 8.14.4 – Georgia Rule 391-3-1-.02(2)(a)7 (LexisNexis 2010) – does not define the terms startup, shutdown and malfunction. The terms are instead defined in the definitions section of the Georgia Air Quality Rules. See Rule 391-3-1-.01 at (nn), (jjj) & (zzz) (LexisNexis 2010). However, the definitions of startup, shutdown, and malfunction provided there are no more specific than the dictionary definitions of those terms,[10] and thus do not provide any meaningful limits on these exempt periods. In order to ensure that the exemptions only apply when necessary, the final permit should specifically and strictly limit the meaning of all these terms so that the periods of exemption do not swallow the emissions limitations.

Startup is the only term that is further defined anywhere in the Draft Permit: "for purposes of" the Draft Permit, startup is "the period lasting from the time the first oil fire is established in the furnace until the time the mill/burner performance and secondary air temperature are adequate to maintain an exit gas temperature above the sulfuric acid dew point." Draft Permit at 4, Condition 3.2.2. This more specific definition would be a step in the right direction, but it is located under the heading "State Only Enforceable Condition." Thus, for purposes of the excess emissions provision, 8.14.4, it is unclear whether the term "startup" has the meaning supplied by Condition 3.2.2, a state only enforceable condition, or the meaning supplied by Rule 391-3-1-.01(zzz), which is part of the SIP. The more precise definition is a more practically enforceable limit on the startup exemption, and thus it should be federally enforceable and clearly applied throughout the permit. The definition should be improved further by including a specific temperature limit rather than the phrase "above the sulfuric acid dew point." In addition, the permit must provide specific, practically enforceable definitions for the terms shutdown and malfunction.

[10] "'[M]alfunction' means mechanical and/or electrical failure of a process, or of air pollution control process or equipment, resulting in operation in an abnormal or unusual manner," Rule 391-3-1-.01(nn), "'shutdown' means the cessation of the operation of a source or facility for any purpose," Rule 391-3-1-.01(jjj), and "'startup' means the commencement of operation of any source." Rule 391-3-1-.01(zzz).

The Draft Permit requires the Plant to "minimize" the length of these exempt periods, and to observe "best operational practices" and "good air pollution control practice" in lieu of the numeric emissions limitations that would otherwise apply. Draft Permit at 57-58. Neither Condition 8.14.4 nor the Draft Permit defines the phrases "best operational practices" and "good air pollution control practice." This omission impermissibly undermines the enforceability of these requirements.

The final permit should translate the terms "best operational practices" and "good air pollution control practice" into specific and objective operational conditions to ensure that they are practicably enforceable. As EPA has stated, "[s]tart-up and shutdown events are part of the normal operation of a source and should be accounted for in the design and implementation of the operating procedure for process control equipment. Accordingly, it is reasonable to expect that careful planning will eliminate violations of emission limitations during such periods." Kathleen M. Bennett, EPA, "Policy on Excess Emissions During Startup, Shutdown, Maintenance and Malfunction" (Sept. 28, 1992). Similarly, prudent planning and design can also help minimize emissions during periods of malfunction. Standard permit conditions for coal-fired electric generating units include particular Best Management Practices as a safeguard to minimize emissions during limitation exemptions for startup, shutdown, and malfunction. To avoid emissions during these periods, operators should be required to continuously monitor boiler conditions, oxygen levels, soot blowers, trouble alarms, precipitator hopper levels, and other monitoring safeguards. The final permit should require that the amount, and not just the duration, of emissions be minimized and include qualifying language such as "at all times" and "to the maximum extent practicable," that would allow for meaningful enforcement. Further, it must require contemporaneous recordkeeping to document the owner or operator's actions during the periods of startup, shutdown or malfunction.

ii. The Permit must Include Separate Criteria for Malfunctions.

As currently written, Condition 8.14.4 fails to acknowledge any distinction between, on the one hand, startup and shutdown, and on the other, malfunction events. All such episodes are treated alike: if it can be shown, presumably by GPC, that (1) best operational practices to minimize emissions were adhered to; (2) pollution control equipment was operated consistent with good air pollution control practices for minimizing emissions; and (3) the duration of excess emissions was minimized, then the source can escape any liability for the excess emissions. This is improper. As EPA has noted, startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the design and implementation of the operating procedures for the process and control equipment. For this reason, EPA has stated that it is reasonable to expect that careful planning will eliminate violations of emission limitations during such periods. See Kathleen M. Bennett, EPA, "Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions" (Sept. 28, 1982). In contrast, if properly defined and limited, a malfunction – whether it occurs during or outside of a startup or shutdown – can be the type of sudden and unavoidable event that produces excess emissions despite the facility's best efforts.

Excess emissions during startup or shutdown can be the result of a malfunction; in such cases, the malfunction should be handled as any other malfunction. However, where there is no alleged malfunction, excess emissions occurring during startup or shutdown must be treated differently because they very likely could have been avoided. As EPA has stated, "[a]ny activity or event which can be foreseen and avoided, or planned, falls outside of the definition of sudden and unavoidable breakdown of equipment." Kathleen M. Bennett, EPA, "Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions," (Feb. 15, 1983).

For these reasons, any affirmative defense provision in Condition 8.14.4 must apply different criteria to alleged malfunctions than it does to startup and shutdown. See Steven A. Herman, EPA, "State Implementation Plans: Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown" (Sept. 20, 1999). If the permit provides an affirmative defense for malfunctions, it must provide that the facility has the burden of proof of demonstrating that:

1. The excess emissions were caused by a sudden, unavoidable breakdown of technology, beyond the control of the owner or operator;

2. That the excess emissions (a) did not stem from any activity or event that could have been foreseen or avoided, or planned for, and (b) could not have been avoided by better operation and maintenance practices;

3. To the maximum extent practicable the air pollution control equipment or processes were maintained and operated in a manner consistent with good practices for minimizing emissions;

4. Repairs were made in an expeditious fashion when the operator knew or should have known that applicable emission limitations were being exceeded. Off-shift labor and overtime must have been utilized, to the extent practicable, to ensure that such repairs were made as expeditiously as practicable;

5. The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

6. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

7. All emission monitoring systems were kept in operation if at all possible;

8. The owner or operator's actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence;

9. The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

10. The owner or operator properly and promptly notified EPD.

For excess emissions occurring during routine startup or shutdown, the provision should state that the permittee has the burden of proof to demonstrate that:

1. The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design;

2. The excess emissions were not part of a recurring pattern indicative of inadequate design, operation or maintenance;

3. If the excess emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable due to an emergency, as per Condition 8.13;

4. At all times, the facility was operated in a manner consistent with good practice for minimizing emissions;

5. The frequency and duration of operation in startup or shutdown mode was minimized to the maximum extent practicable;

6. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

7. All emission monitoring systems were kept in operation if at all possible;

8. The owner or operator's actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence; and

9. The owner or operator properly and promptly notified the appropriate regulatory authority.

Finally, the provision should make it clear that if excess emissions occur during routine startup or shutdown periods due to malfunction, then such instances will be treated the same as other malfunctions.

d. Condition 8.14.4 Must Be Revised to Address National Emissions Standards for Hazardous Air Pollutants.

As currently written, paragraph (c) states that the provisions of Condition 8.14.4 do not apply to sources subject to New Source Performance Standards. This paragraph must be rewritten to make it clear that the affirmative defense provision does not apply to any federally promulgated performance standards or emission limits, including not just new source performance standards but also national emissions standards for hazardous air pollutants (NESHAPS). See Steven A. Herman, EPA, "State Implementation Plans: Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown" (Sept. 20, 1999). As EPD is aware, EPA has promulgated a NESHAP for utility boilers that is due to become final and effective on November 16, 2011, and thus will be applicable during the Permit's term. See infra Part IX.

VII. Coal Handling System

The Draft Permit does not include or meet regulatory requirements for fugitive emissions from solid fuel handling systems. Fuel handling systems, particularly those for coal-fired power plants such as this Plant, can release significant amounts of PM into the air near the facility. These emissions are at ground level, heightening their impact on air quality and human health in the immediate vicinity of the Plant.

Georgia regulations include a non-exhaustive list of specific control devices and practices that should be applied to this facility and detailed in its Title V permit as enforceable conditions of its operation. These include the application of water or other dust suppressants on surfaces or operations that can give rise to airborne dust, and "[i]nstallation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials. Ga. Comp. R. & Regs. r. 391-3-1-.02(2)(n)1. The Draft Permit subjects the coal handling system to an opacity limit of twenty per cent as required by Ga. Comp. R. & Regs. r. 391-3-1-.02(2)(n)2, but does not include the specific, enforceable best management practices necessary to eliminate or minimize fugitive dust from this component of the plant. Draft Permit at 7. Rather, GPC is required to take "reasonable precautions." Id. This requirement is vague and unenforceable.

Specific work practice standards can and should be applied to this major PM emissions source and made enforceable in its Title V permit. The permit provisions covering the solid fuel handling system should specify and require the "reasonable precautions" appropriate to this facility. The permit should include enforceable conditions requiring enclosures and other control devices that are demonstrated to eliminate PM emissions from the fuel handling system. These devices should be described in more detail in the permit or narrative, and should be subject to monitoring and reporting to demonstrate compliance with a 20% opacity limit, so that the public can evaluate their efficacy and, when necessary, seek enforcement of any violations. The required frequency, quantity and duration of dust suppression techniques should also be included in the Draft Permit.

VIII. Greenhouse Gas Monitoring and Reporting

As described above, Title V permits must include "all applicable requirements" that will exist during the permit term. Greenhouse gas monitoring and reporting requirements were promulgated on October 30, 2009 and amended on July 12, 2010. 40 C.F.R. § 98 (LexisNexis 2011). However, the Draft Permit does not identify these requirements as applicable to Plant Scherer. EPA Guidance specifically addresses how greenhouse gases are to be handled under Title V of the Clean Air Act and its Amendments, stating that "as with other applicable requirements related to non-GHG pollutants, any applicable requirement for GHGs must be addressed in the title V permit (*i.e.*, the permit must contain conditions necessary to assure compliance with applicable requirements for GHGs)." U.S. EPA, Office of Air and Radiation, "PSD And Title V Permitting Guidance For Greenhouse Gases" at 52 (March 2011), *available at* http://www.epa.gov/region07/air/title5/t5memos/ghgguid.pdf. EPD must include conditions in Part 2.0, Part 3.0, Part 5.0 and Part 6.0 of the permit specifying the recordkeeping and monitoring requirements of 40 CFR §§ 98.43, 98.44, and 98.47.

IX. Hazardous Air Pollutants

As noted supra, CAA 504(a) requires each Title V permit to "assure compliance with applicable requirements of this chapter, including the requirements of the applicable implementation plan [SIP]." 40 C.F.R. § 70.2 defines "applicable requirements" as including "requirements that have been promulgated or approved by EPA through rulemaking at the time of issuance but have future effective compliance dates."

On March 16, 2010, EPA issued the proposed National Emissions Standards for Hazardous Air Pollutants ("NESHAP") for coal-fired electric steam generating units ("EGU MACT") and proposed revisions to the New Source Performance Standards ("NSPS") for these sources. The EGU MACT rule will apply to all hazardous air pollutants and will set emission standards based upon Maximum Achievable Control Technology ("MACT"). 42 U.S.C. §

7412(d)(2) (LexisNexis 2011). The NSPS will apply to criteria and other, non-HAP pollutants, and will set emission standards based on the Best Adequately Demonstrated Technology. 42 U.S.C. § 7411(d) (LexisNexis 2011). EPA has proposed these new rules and they will apply to the Plant during the Title V permit term. Thus, the final permit should reflect the fact that the Draft Permit's Reopening for Cause provision requires that the Permit will have to be reopened within 18 months of the promulgation of this rule, and modifications will have to be made to control the emissions of these hazardous air pollutants. See Draft Permit at 53, Condition 8.11.1(a).

We thank you for the opportunity to submit these comments. We look forward to receiving the Department's response to our comments and to receiving notice of the Department's final permit decisions.

Respectfully submitted,

Kurt D. Ebersbach
Senior Attorney
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John Suttles by KDE w/ express permission

John Suttles
Senior Attorney
Southern Environmental Law Center

On behalf of GreenLaw, the Southern Environmental Law Center, and the Sierra Club

Facility Name: **Scherer Steam-Electric Generating Plant**
City: Juliette
County: Monroe
AIRS #: 04-13-207-00008

Application #: TV-19764
Date Application Received: June 28, 2010
Permit No: 4911-207-0008-V-03-0

Program	Review Engineers	Review Managers
SSPP	Fred Francis	Furqan Shaikh
ISMP	Dave Sheffield	DeAnna Oser
SSCP	Pierre Sanon	James Eason
Toxics	n/a	n/a
Permitting Program Manager		Eric Cornwell

Introduction

This narrative is being provided to assist the reader in understanding the content of the attached draft Part 70 operating permit. Complex issues and unusual items are explained here in simpler terms and/or greater detail than is sometimes possible in the actual permit. This permit is being issued pursuant to: (1) Georgia Air Quality Act, O.C.G.A § 12-9-1, et seq. and (2) Georgia Rules for Air Quality Control, Chapter 391-3-1, and (3) Title V of the Clean Air Act. Section 391-3-1-.03(10) of the Georgia Rules for Air Quality Control incorporates requirements of Part 70 of Title 40 of the Code of Federal Regulations promulgated pursuant to the Federal Clean Air Act. The primary purpose of this permit is to consolidate and identify existing state and federal air requirements applicable to **Scherer Steam-Electric Generating Plant** and to provide practical methods for determining compliance with these requirements. The following narrative is designed to accompany the draft permit and is presented in the same general order as the permit. It initially describes the facility receiving the permit, the applicable requirements and their significance, and the methods for determining compliance with those applicable requirements. This narrative is intended as an adjunct for the reviewer and to provide information only. It has no legal standing. Any revisions made to the permit in response to comments received during the public participation and EPA review process will be described in an addendum to this narrative.

I. Facility Description

A. Facility Identification

1. Facility Name: Scherer Steam-Electric Generating Plant

2. Parent/Holding Company Name: Southern Company / Georgia Power Company

3. Previous and/or Other Name(s): This facility is commonly known, and referred to as Plant Scherer. No other names have been identified.

4. Facility Location

   10986 Highway 87
   Juliette, GA 31046 (Monroe County)

5. Attainment, Non-attainment Area Location, or Contributing Area

   Area is designated as non-attainment area for the 8-hour Ozone standard and $PM_{2.5}$ standard.

B. Site Determination

There are no other facilities which could possibly be contiguous or adjacent and under common control.

C. Existing Permits

Table 1 below lists all current Title V permits, all amendments, 502(b)(10) changes, and off-permit changes, issued to the facility, based on a comparative review of form A.6, Current Permits, of the Title V application and the "Permit" file(s) on the facility found in the Air Branch office.

Table 1: List of Current Permits, Amendments, and Off-Permit Changes

Permit Number and/or Off-Permit Change	Date of Issuance/ Effectiveness	Purpose of Issuance
4911-207-0008-V-02-0	11/15/2005	Title V Renewal Permit with Effective Date of January 1, 2006
4911-207-0008-V-02-1	12/12/2006	Removal of Condition 5.2.14 (which required a daily inspection of emission units without air pollution control devices). Modification of Condition 3.3.1(to add coal handling system as emission unit).
4911-207-0008-V-02-2	03/07/2007	Incorporate changes made to Georgia Rules for Air Quality Control 391-3-1-.02(2)(jjj).
4911-207-0008-V-02-3	09/17/2008	Allow the use of method ASTM D5142 or ASTM D3173 to analyze coal samples for moisture content and add compliance dates for Scherer according to the Georgia Multipollutant Rule 391-3-1-.02(2)(sss).
4911-207-0008-V-02-4	12/02/2008	Construct and operate Powdered Activated Carbon (PAC) injection with Baghouse to Steam Generating Units SG01, SG02, SG03, and SG04. Add Method D1552 to Condition 6.2.3. Add "State Only Enforceable" to Condition 8.17.2.

4911-207-0008-V-02-5	03/12/2009	Update the Title IV Acid Rain Phase II NOx Averaging Plan.
4911-207-0008-V-02-6	05/29/2009	Update to the Georgia Multipollutant Rule 391-3-1-.02(2)(sss) as approved by the DNR Board on December 3, 2008.
4911-207-0008-V-02-7	11/16/2009	Replace the existing high pressure section of the steam turbine for Unit SG03 with a more efficient design.
4911-207-0008-V-02-8	09/17/2009	Incorporate the requirements of 40 CFR 96 for Clean Air Interstate Rule (CAIR) for the SO_2 and NO_X Annual Trading Programs.
4911-207-0008-V-02-A	02/23/2010	Replace the existing high pressure section of the steam turbine for Units SG01, SG02, and SG04 with a more efficient design. 502(b)(10) change.
4911-207-0008-V-02-B	05/12/2010	Construction and operation of flue gas desulfurization, and SCR pollution control systems in accordance with Georgia Rule 391-3-1-.02(2)(sss). Change the frequency of required particulate matter testing, and add conditions related to the Material Handling System that must meet 40 CFR 60 Subpart OOO standards.
4911-207-0008-V-02-C	11/23/1010	Allow the steam generating units to continue to qualify for a deferred biannual particulate testing schedule until the scrubbers are required by Georgia Rule (sss). Describe the installation location of the Continuous Opacity Monitoring System (COMS) by specifying that it be installed upstream of the wet scrubbers.

D. Process Description

1. SIC Codes(s)

4911

The SIC Code(s) identified above were assigned by EPD's Air Protection Branch for purposes pursuant to the Georgia Air Quality Act and related administrative purposes only and are not intended to be used for any other purpose. Assignment of SIC Codes by EPD's Air Protection Branch for these purposes does not prohibit the facility from using these or different SIC Codes for other regulatory and non-regulatory purposes.

Should the reference(s) to SIC Code(s) in any narratives or narrative addendum previously issued for the Title V permit for this facility conflict with the revised language herein, the language herein shall control; provided, however, language in previously issued narratives that does not expressly reference SIC Code(s) shall not be affected.

2. Description of Product(s)

Scherer Steam-Electric Generating Plant generates electricity for sale.

3. Overall Facility Process Description

This facility has four steam generating units. Each unit's primary fuel is bituminous coal, although they may burn small quantities of other fuels such as wood or #2 fuel oil. Steam generated by each boiler is passed through a steam turbine to generate electricity for sale.

The facility also has two start-up boilers which can be used during the start-up of a steam generating unit when steam supply is not available from any other unit. As a result, the start-up boilers are rarely used.

Each steam generating unit is currently in the process of being equipped with selective catalytic reduction, flue gas desulfurization, sorbent injection and a baghouse to meet the requirements of Georgia Rule (sss), and eventually the requirements of Georgia Rule (uuu).

4. Overall Process Flow Diagram

The facility provided a process flow diagram in their Title V permit application.

E. Regulatory Status

1. PSD/NSR

This facility is a major source under PSD because it has potential emissions of PM, SO_2, NO_X, VOC, and CO greater than 100 tpy (it is one of the 28 named source categories under PSD). The facility was originally constructed before the PSD regulations were effective.

2. Title V Major Source Status by Pollutant

Table 2: Title V Major Source Status

Pollutant	Is the Pollutant Emitted?	If emitted, what is the facility's Title V status for the pollutant?		
		Major Source Status	Major Source Requesting SM Status	Non-Major Source Status
PM	✓	✓		
PM_{10}	✓	✓		
SO_2	✓	✓		
VOC	✓	✓		
NO_x	✓	✓		
CO	✓	✓		
TRS	n/a			
H_2S	n/a			
Individual HAP	✓	✓		
Total HAPs	✓	✓		

3. MACT Standards

This facility is major for HAPs. It is not subject to MACT standard 40 CFR 63 Subpart DDDDD for industrial/commercial/institutional boilers and process heaters because the facility has electric utility steam generating units that produce electricity for sale, are fossil fuel-fired, and larger than 25 megawatts, therefore exempt in §63.7491(c) of the standard.

Since this facility is a major source of HAP emissions, it could be subject to a future MACT standard for electric utility steam generating units.

4. Program Applicability (AIRS Program Codes)

Program Code	Applicable (y/n)
Program Code 6 - PSD	N
Program Code 8 – Part 61 NESHAP	N
Program Code 9 - NSPS	Y
Program Code M – Part 63 NESHAP	N
Program Code V – Title V	Y

Regulatory Analysis

II. Facility Wide Requirements

A. Emission and Operating Caps:

None applicable.

B. Applicable Rules and Regulations

None applicable.

C. Compliance Status

This facility is operating in compliance with its air quality permit.

D. Operational Flexibility

None applicable.

E. Permit Conditions

None applicable.

III. Regulated Equipment Requirements

A. Brief Process Description

The facility consists of four tangentially fired steam generating units which primarily burn coal, with a maximum continuous heat input between 9494 and 9874 MMBtu/hr, and related support equipment. Steam from each generating units is used to turn a steam turbine, which drives an electric generator, producing electricity for sale.

Emission Unit ID No.	Emission Unit Description	Max. Heat Input Capacity (MMBtu/hr)	Max. Continuous Heat Input (MMBtu/hr)	Fuel Burning Configuration
SG01	Steam Generator Unit 1	9860	7740	Tangentially-fired
SG02	Steam Generator Unit 1	9874	7740	Tangentially-fired
SG03	Steam Generator Unit 1	9495	7740	Tangentially-fired
SG04	Steam Generator Unit 1	9494	7740	Tangentially-fired

B. Equipment List for the Process

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	Description	Applicable Requirements/Standards	Corresponding Permit Conditions	ID No.	Description
SG01	Steam Generator Unit 1	391-3-1-.02(2)(b), (d), (g), (jjj), (sss), (uuu) 40 CFR 60 Subpart A, 40 CFR 60 Subpart D, Acid Rain and CAIR	3.2.1, 3.2.2, 3.2.4, 3.3.1 to 3.3.5, 3.4.6, 3.4.10, 3.4.11, 3.4.13, 3.4.14, 3.4.18, 3.4.19, 4.2.1, 4.2.4, 5.2.1 to 5.2.6, 5.2.10 to 5.2.24, 6.1.7, 6.2.1, 6.2.2, 6.2.7 to 6.2.10, 6.2.13 to 6.2.19, 7.9.7, 7.15.2	SCR1 EP01 BH01 FGD1	Selective Catalytic Reduction ESP Baghouse with PAC Flue Gas Desulfurization
SG02	Steam Generator Unit 2	391-3-1-.02(2)(b), (d), (g), (jjj), (sss), (uuu) 40 CFR 60 Subpart A, 40 CFR 60 Subpart D, Acid Rain and CAIR	3.2.1, 3.2.2, 3.2.4, 3.3.1 to 3.3.5, 3.4.7, 3.4.10, 3.4.11, 3.4.13, 3.4.14, 3.4.17, 3.4.19, 4.2.1, 4.2.4, 5.2.1 to 5.2.5, 5.2.7, 5.2.10 to 5.2.24, 6.1.7, 6.2.1, 6.2.2, 6.2.7 to 6.2.10, 6.2.13 to 6.2.19, 7.9.7, 7.15.2	SCR2 EP02 BH02 FGD2	Selective Catalytic Reduction ESP Baghouse with PAC Flue Gas Desulfurization
SG03	Steam Generator Unit 3	391-3-1-.02(2)(b), (d), (g), (jjj), (sss), (uuu) 40 CFR 60 Subpart A, 40 CFR 60 Subpart D, Acid Rain and CAIR	3.2.1, 3.2.2, 3.2.4, 3.3.1 to 3.3.5, 3.4.8, 3.4.10, 3.4.11, 3.4.13 to 3.4.15, 3.4.19, 4.2.1, 4.2.4, 5.2.1 to 5.2.5, 5.2.8, 5.2.10 to 5.2.24, 6.1.7, 6.2.1, 6.2.2, 6.2.7 to 6.2.10, 6.2.13 to 6.2.19, 7.9.7, 7.15.2	SCR3 EP03 BH03 FGD3	Selective Catalytic Reduction ESP Baghouse with PAC Flue Gas Desulfurization

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	Description	Applicable Requirements/Standards	Corresponding Permit Conditions	ID No.	Description
SG04	Steam Generator Unit 4	391-3-1-.02(2)(b), (d), (g), (jjj), (sss), (uuu) 40 CFR 60 Subpart A, 40 CFR 60 Subpart D, Acid Rain and CAIR	3.2.1, 3.2.2, 3.2.4, 3.3.1 to 3.3.5, 3.4.9, 3.4.10, 3.4.11, 3.4.13, 3.4.14, 3.4.16, 3.4.19, 4.2.1, 4.2.4, 5.2.1 to 5.2.5, 5.2.9 to 5.2.24, 6.1.7, 6.2.1, 6.2.2, 6.2.7 to 6.2.10, 6.2.13 to 6.2.19, 7.9.7, 7.15.2	 SCR4 EP04 BH04 FGD4	Selective Catalytic Reduction ESP Baghouse with PAC Flue Gas Desulfurization
SB01	Start-up Boiler Unit 1	391-3-1-.02(2)(d) and (g)	3.2.3, 3.4.1, 3.4.2, 3.4.3, 6.1.7	none	n/a
SB02	Start-up Boiler Unit 2	391-3-1-.02(2)(d) and (g)	See SB01	none	n/a
CHS	Coal Handling System	40 CFR 60 Subpart A, 40 CFR 60 Subpart Y, 391-3-1-.02(2)(n)	3.3.1, 3.3.6, 3.4.4, 6.2.5	none	n/a
AHS	Ash Handling System	391-3-1-.02(2)(n)	3.4.4, 3.4.5, 3.4.6, 6.2.6	none	n/a
MHS	Materials Handling System	391-3-1-02(2)(e) 391-3-1-.02(2)(n) 40 CFR 60 Subpart A 40 CFR 60 Subpart OOO	3.3.1, 3.3.7, 3.4.4, 3.4.5, 3.4.12, 4.2.2, 4.2.3, 5.2.17, 6.1.7, 6.2.13	LSBA LSBB	Limestone Silo Baghouse A Limestone Silo Baghouse B

* Generally applicable requirements contained in this permit may also apply to emission units listed above. The lists of applicable requirements/standards and corresponding permit conditions are intended as a compliance tool and may not be definitive.

C. Equipment & Rule Applicability

Equipment and Rule Applicability specified in Permit No. 4911-207-0008-V-01-0 is discussed in the initial Title V permit narrative for this permit. Please refer to this narrative.

Permit Amendment No. 4911-207-0008-V-02-1 (Issued December 12, 2006)
Condition 5.2.14 that required daily inspection of equipment that didn't use any pollution control devices was removed. The condition only applied to the start-up boilers which are used very infrequently, and burn distillate oil. Wording of condition 3.3.1 was modified to clarify that NSPS General Provisions apply to the entire facility, specifically including the Coal Handling Equipment (40 CFR 60, Subpart Y).

Permit Amendment No. 4911-207-0008-V-02-2 (Issued March 7, 2007)
This amendment incorporated changes made to Georgia Rules for Air Quality Control 391-3-1-.02(2)(jjj). The revised rules include lowering the seven-plant ozone season NOx average from 0.20 lb/MMBtu to 0.18 lb/mmBtu and a new site-average NOx rate for Plant Scherer of 0.17 lb/MMBtu effective May 1, 2007. In addition, there are new specific unit targets for Plants Scherer and Branch. For Plant Scherer, the revised unit targets are 0.20 lb/MMBtu, 0.17 lb/MMBtu, 0.15 lb/MMBtu, and 0.16 lb/MMBtu for Units 1, 2, 3 and 4 respectively. For Plant Branch, the revised unit targets are 0.55 lb/MMBtu for Units 1 & 2 and 0.45 lb/MMBtu for Units 3 & 4. The unit targets at the other five plants will remain unchanged. At these NOx emission rates, Georgia Power plants will be in compliance with the five-plant, seven-plant and Scherer-site ozone season NOx averages listed under 391-3-1-.02(2)(jjj).

Permit Amendment No. 4911-207-0008-V-02-3 (Issued September 17, 2008)
This amendment allowed for the use of method ASTM D5142 or ASTM D3173 to analyze coal samples for moisture content. Although Georgia Power asked to use method ASTM D5142 in lieu of ASTM D3173, EPD's Source Monitoring Program has indicated that both methods should be left in the permit since the D3173 (manual) method is the reference method. Changes were also made to add compliance dates for Scherer according to the Georgia Multi-pollutant Rule 391-3-1-.02(2)(sss).

Permit Amendment No. 4911-207-0008-V-02-4 (Issued December 2, 2008)
This amendment required installation of sorbent injection equipment as well as a baghouse for each of the steam generating units for control of mercury emissions, per Georgia Rule (sss). The sorbent used is PAC, or Powdered Activated Carbon. The PAC injection and baghouse equipment were added to the equipment list in Section 3.1 of the permit, and standard conditions were added related to monitoring, record keeping, and reporting requirements for the baghouses. Georgia Rule (sss) specifies no emission limits, operating caps, or control efficiency requirements, as it only requires that this equipment is installed and operated.

Permit Amendment No. 4911-207-0008-V-02-5 (Issued March 12, 2009)
This application was a significant modification without construction because this permit application requires changes to the current NO_X averaging plan. The facility has requested to update the Title IV Acid Rain Program Phase II NO_X averaging plan for years 2009 to 2013 for Emission Units SG01, SG02, SG03 and SG04. The facility has requested to use the Title IV fast-track modification option in accordance with 40 CFR 72.82 to update the NO_X averaging plan.

Permit Amendment No. 4911-207-0008-V-02-6 (Issued May 29, 2009)
Old Conditions 3.2.5 and 3.2.6 were revised to reflect the updates to the Georgia Multipollutant Rule 391-3-1-.02(2)(sss) as approved by the DNR Board on December 3, 2008. These conditions were marked "State Only Enforceable", until EPA approval of Georgia Rule 391-3-1-.02(2)(sss), as submitted in EPD's SIP, at which time it will become federally enforceable. In a subsequent amendment, these conditions were updated, and were moved to section 3.4 as New Conditions 3.4.13 and 3.4.14.

Permit Amendment No. 4911-207-0008-V-02-7 (Issued November 16, 2009)
This amendment was a 502(b)(10) change for the replacement of the high-pressure steam turbine section for steam generating unit SG03. No new emissions units were installed, and no new rules were triggered, as this equipment doesn't produce emissions.

Permit Amendment No. 4911-207-0008-V-02-8 (Issued September 17, 2009)
This application is processed as a significant modification without construction because this permit amendment incorporates the requirements of 40 CFR 96 for Clean Air Interstate Rule (CAIR) for the SO_2 and NO_X Annual Trading Programs for Emission Units SG01, SG02, SG03 and SG04 (denoted simply as Unit ID Nos. 1, 2, 3, and 4 in CAIR Permit Application) in Section 7.15 and Attachment E. The facility is required to comply with the CAIR requirements in accordance with the Georgia Rules 391-3-1-.02(12) and 391-3-1-.02(13), and 40 CFR 96.121, 96.122, 96.221, 96.222, 96.321, and 96.322.

Permit Amendment No. 4911-207-0008-V-02-A (Issued February 23, 2010)
This amendment was a 502(b)(10) change for the replacement of the high-pressure steam turbine sections for steam generating units SG01, SG02, and SG04. No new emissions units were installed, and no new rules were triggered.

Permit Amendment No. 4911-207-0008-V-02-B (Issued May 12, 2010)
This amendment covered the installation of SCR, and flue gas desulfurization equipment on all 4 steam-generating units per Georgia Rule (sss). The SCR and flue gas desulfurization equipment were added to the equipment list in section 3.1 of the permit, and updated standard conditions were added in section 3.4 to specify the requirements of Georgia Rule (sss).

Permit Amendment No. 4911-207-0008-V-02-C (Issued November 23, 2010)
This amendment requested that the steam generating units continue to qualify for a deferred biannual particulate testing schedule until the scrubbers are required by Georgia Rule (sss). Condition 5.2.1 was also clarified to describe the location of the Continuous Opacity Monitoring System (COMS) by specifying that it be installed upstream of the wet scrubbers.

Title V Application No. 20128 received December 27, 2010
This application was to incorporate conditions for compliance with Georgia Rules (sss) and (uuu). The necessary conditions were rolled into this renewal permit.

Title V Application No. 20146 received December 27, 2010
This application requested that SO_2 emissions be measured with the newly installed CEMS rather than estimated with coal sampling, and that the CEMS output be accepted to show compliance with SO_2 emission limits in 40 CFR 60 Subpart D. The necessary conditions were rolled into this renewal permit.

Title V Application No. 20525 received June 23, 2011
This application requested modifications to the CAM plan to incorporate the number of FGD pumps running in addition to the opacity measured by the COMS as an indicator of compliance. A modification of Condition 6.1.7 was also requested to change the conditions that would be considered an excursion.

Title V Application No. 20826 received November 14, 2011
This application requested changes in the periodic report deadlines, from 30 days after the reporting period, to 60 days.

Emission and Operating Caps:

Equipment Caps: The types of fuel burned in the steam generating units have been limited to coal, coal derived synthetic fuel, No 2 Fuel oil, sawdust, biomass, and used oil. The total tons of NO_X emissions are limited to 32,335.8 tons for all of the steam generating units at 7 Georgia Power Plants including, Bowen, Branch, Hammond, McDonough, Scherer, Wansley, and Yates on a combined basis for the ozone season each year.

Federal Limits: Several NSPS federal limits apply to the equipment at Plant Scherer.

From each steam-generating unit: Particulate matter emissions are limited to 0.10 lb/MMBtu heat input. Opacity is limited to 20 percent over a 6-minute average, except for one 6-minute period per hour of not more than 27 percent. Sulfur dioxide is limited to 1.2 lb/MMBtu heat input. Nitrogen Oxide emissions are limited to 0.7 lb/MMBtu heat input.
From the coal handling system: Opacity is limited to 20 percent.

From the material handling system: Fugitive emissions are limited to 12 percent opacity from any crusher at which a capture system is not used. Stack emissions are limited to 0.014 gr/dscf. Fugitive emissions from any screening operation, belt conveyor transfer point, storage bin, enclosed truck or railcar loading station, or from any other affected equipment, are limited to 7 percent opacity. Visible emissions of any kind are not allowed from a wet screening operation, subsequent operation, bucket elevator, or belt conveyor that process saturated material in the production line up to the next crusher, mill, or stage bin. Visible emissions of any kind are also not allowed from any screening operations, bucket elevators, or belt conveyors in the production line downstream of wet mining operations where such screening operations, bucket elevators, and belt conveyors process saturated materials up to the first crusher, grinding mill, or storage bin in the production line. From the material handling system equipment located inside of a building: Visible emissions are limited to 7 percent opacity. Emissions from a powered building vent are limited to 0.014 gr/dscf.

State Limits: Several SIP Rule Standards apply to the equipment at Plant Scherer.

From the startup boilers: The particulate emissions rate is limited to $E=0.5 \times (10/R)^{0.5}$ where E equals the allowable particulate emission rate in lb/MMBtu heat input, and R equals the heat input in MM/BTU/hr. Opacity is limited to 20 percent on a 6-minute average except for one 6-minute period per hour of not more than 27 percent opacity. Fuel shall not be fired containing more than 3 percent sulfur by weight.

From the Ash handling system: The Permittee should take all precautions to prevent fugitive dust from becoming airborne, and keep the opacity less that 20 percent.

From the steam generating units: NO_X emissions are capped during the ozone season on a 30-day rolling average at 0.20 lb/MMBtu, 0.17 lb/MMBtu, 0.15 lb/MMBtu, and 0.16 lb/MMBtu for steam generating units SG01, SG02, SG03, and SG04 respectively, or alternatively under 0.18 lb/MMBtu averaged over all affected units at Plants Bowen, Branch, Hammond, McDonough, Scherer, Wansley, and Yates, or alternatively, NO_X emissions may be kept under 0.17 lb/MMBtu during ozone season averaged over all affected units at Plant Scherer, on a 30-day rolling average period. The steam generating units must currently be operated with sorbent injection and a baghouse, except under specific circumstances. Starting on December 31, 2011, steam generating unit SG03 must operate with flue gas desulfurization and selective catalyst reduction, except under specific circumstances. Units SG04, SG02, and SG01 will be phased in one each year, to operate with FGD and SCR. Starting on January 1, 2012 steam generating unit SG03 must limit its SO_2 emissions to less than 5 percent of the potential combustion concentration on a

30-day rolling average basis, except under specific circumstances. Units SG04, SG02, and SG01 will be phased in, one each year, and be required to meet this SO_2 reduction requirement.
For the Material Handling system: The particulate emission rate is limited to $E = 4.1P^{0.67}$ for process input weight rates up to and including 30 tons/hr, and limited to $E = 55P^{0.11} - 40$ for process input weight rates above 30 tons/hr, where E equals the allowable PM emission rate in pounds per hour and P equals the total dry process input weight rate in tons per hour.

Rules and Regulations Assessment:

State Rules
Steam Generating Units 1, 2, 3 and 4 (Emission Unit IDs SG01, SG02, SG03 and SG04) are subject to Georgia Rules for Air Quality Control 391-3-1-.02(2)(b) and (d) for visible emissions and particulate matter emissions. Georgia Power has indicated that emissions, including PM, can either be vented to the ESP and then the FGD scrubber or in the event of scrubber malfunction, emissions can be vented to the ESP only. Under normal operation, the ESP would only be used to remove ash from the gypsum so that it meets quality standards for purchase.

Gypsum produced from the limestone scrubbing material will be removed from the scrubber, will undergo dewatering, and will be loaded into railcars. Since the limestone will be converted to gypsum, Georgia Rules for Air Quality Control 391-3-1-.02(2)(e) applies to the Material Handling System.

Sulfur contained in the coal burned in each of the steam generating units, produces SO_2 gas in the exhaust gas stream. Georgia Rules for Air Quality Control 391-3-1-.02(2)(g) limits the amount of SO_2 in the stack for each of the boilers.

Georgia Rules for Air Quality Control 391-3-1-.02(2)(n) applies to all sources of fugitive dust emissions. The Coal Handling System (Emission Unit ID CHS), Material Handling System (Emission Unit ID MHS), and Ash Handling System (Emission Unit ID AHS) must comply with the opacity limit of 20 percent.

Georgia Rules for Air Quality Control 391-3-1-.02(2)(jjj) applies to all coal-fired electric utility generating units with a maximum heat input greater than 250 MMBtu/hr. Specifically 391-3-1-.02(2)(jjj)(6) applies to Plant Scherer. The rule requires all affected units on site to not exceed 0.17 lb NO_X/MMBtu heat input on a 30 day rolling average during the ozone season, and all affected units in the area (7-Plant rule) to not exceed 0.18 lb NO_X/MMBtu heat input on a 30 day rolling average during the ozone season, May 1 through September 30 of each year.

Georgia Rules for Air Quality Control 391-3-1-.02(2)(sss) specifically states that steam-generating units at Plant Scherer, SG01, SG02, SG03, and SG04 shall be equipped and operated with sorbent injection, baghouse, selective catalytic reduction (SCR), and flue gas desulfurization (FGD). The applicability dates for installation of the sorbent injection, and baghouse equipment on all units have passed. SCR and FGD must be phased in on all units going forward. There are no emission limits, or control efficiencies required by this rule. SO_2 CEMs required to monitor the FGD scrubber efficiency have been installed, and will be used to monitor compliance with sulfur limits in Georgia Rule (g), and 40 CFR 60 Subpart D, in place of the coal bunker sulfur analysis.

Georgia Rules for Air Quality Control 391-3-1-.02(2)(uuu) requires that affected units at Plant Scherer not emit gases which contain sulfur dioxide in excess of 5 percent of the potential combustion concentration determined over a 30-day rolling average basis, excluding specifically defined periods in the rule (startup, shutdown, malfunction etc.) The rule specifies periods when the standards do not apply, and dates when the limitations become effective at the specific units. Units 3, 4, 2, and 1 must meet these standards starting on January 1, 2012, January 1, 2013, January 1, 2014, and January 1, 2015 respectively. Conditions related to this rule have been added in this renewal permit.

Federal Rules
40 CFR 60 Subpart A –General Provisions, applies to all facilities which are subject to another subpart under 40 CFR 60. Because emissions units are subject to several subparts, the general provisions also apply.

40 CFR 60 Subpart D applies to emission units SG01, SG02, SG03, and SG04 which were all under construction after August 17, 1971 but before September 18, 1978. They all are all capable of combusting more than 250 mmBtu/hr heat input of fossil fuel. As a result, they are subject to 40 CFR 60 Subpart D, which has an effective date of August 17, 1971. They are not subject to 40 CFR 60 Subpart Da since they were under construction before the applicable effective date of September 18, 1978.

40 CFR 60 Subpart Y - Standards of Performance for Coal Preparation Plants, applies to the coal handling system. Subpart Y applies to any of the following sources in coal preparation plants which process more than 200 tons per day and which commenced construction or modification after October 24, 1974: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems. Since Plant Scherer does not have any thermal dryers or pneumatic coal cleaning equipment, the only emission standard they are subject to in Subpart Y is the opacity standard in 40 CFR 60.252(c).

40 CFR 60 Subpart OOO applies to the material handling system which process nonmetallic minerals, specifically limestone used in the FGD, and consists of any crusher, grinding mill, screening operation, bucket elevator, belt conveyor, bagging operation, storage bin, enclosed truck or railcar loading station which are used to process the limestone.

40 CFR Part 64 Compliance Assurance Monitoring (CAM) applies to a pollutant-specific emissions unit at a major source that is required to obtain a part 70 or 71 permit if the unit satisfies all of the following criteria:

(1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof), other than an emission limitation or standard that is exempt;

(2) The unit uses a control device to achieve compliance with any such emission limitation or standard; and

(3) The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source. For purposes of this paragraph, "potential pre-control device emissions" shall have the same meaning as "potential to emit," as defined in §64.1, except that emission reductions achieved by the applicable control device shall not be taken into account. Since the potential pre-control device emissions of PM are greater than or equal to 100 TPY, SG01, SG02, SG03 and SG04 and the associated FGD Scrubber and ESP are subject to provisions of 40 CFR Part 64 for control of PM.

D. Compliance Status

The facility is currently in compliance with all applicable regulations.

E. Operational Flexibility

None applicable.

F. Permit Conditions

Carried over Conditions
Condition 3.2.2 prohibits the Permittee from burning used oil in the steam generating units during startup or shutdown, and was modified to include the definition of shutdown.

Condition 3.2.4 sets the overall NO_X emissions limit during the ozone season each year in tons for 7 Georgia Power Plants.

Conditions 3.3.2, and 3.3.3 set the particulate matter emissions limit, and opacity limit respectively for the steam generating units.

Conditions 3.3.4, and 3.3.5 set the sulfur dioxide, and nitrogen oxides emission limits respectively.

Condition 3.3.6 sets the opacity limit for the coal handling system at 20 percent.

Conditions 3.4.1, and 3.4.2 set the particulate matter emissions limit, and opacity limit respectively for the startup boilers.

Condition 3.4.3 sets the fuel sulfur limit for the startup boilers at 3.0 percent by weight.

Changed or new Conditions since the last renewal
Conditions 3.2.1 sets what fuels are allowed to be burned in the steam generating units, and was modified to add biodiesel, and biodiesel blends to the oils that are allowed.

Condition 3.2.3 sets what fuel is allowed to be burned in the startup boilers, and was modified from its original version to add biodiesel, or biodiesel blends to the allowed fuels for the start up boilers.

Wording of condition 3.3.1 is changed to encompass the entire facility, specifically the coal handling equipment, as well as the coal-fired boilers.

Condition No. 3.3.7 is added to provide emission standards for compliance with 40 CFR Part 60 Subpart OOO.

Condition Nos. 3.4.4 and 3.4.5 are modified to include the Rule (n) requirements for the Material handling System (MHS). Condition 3.4.5 was modified to remove the opacity limit from the Coal Handling System (CHS), as this limit was already contained in condition 3.3.6.

Conditions 3.4.6-3.4.9 are updated to incorporate changes made to Georgia Rule (jjj) that lowered the allowable ozone season NO_X emission rates from each of the individual units at Plant Scherer.

Condition 3.4.10 is updated to incorporate changes made to Georgia Rule (jjj) that lowered the allowable ozone season 5-plant, and 7-plant average NOx emission rates.

Condition No. 3.4.11 is added to implement a Scherer-site wide limit for all four steam generating units at the plant per Georgia Rule (jjj).

New Condition 3.4.12 subjects the material handling system to Georgia Rule (e) PM limit.

New Condition Nos. 3.4.13 and 3.4.14 contain the updated Georgia Rule (sss) conditions.

New Conditions 3.4.15 through 3.4.18 limit SO_2 emissions to 5% of the potential combustion concentration on a 30-day rolling average for emissions units SG03, SG04, SG02, and SG01 on their respective effective dates per Georgia Rule (uuu).

New Condition 3.4.19 states the times that the sulfur reduction requirements in Conditions 3.4.15 through 3.4.18 are not required to be met, which are generally startups, shutdowns, restarts, maintenance, malfunctions, testing, and R&D.

IV. Testing Requirements (with Associated Record Keeping and Reporting)

A. General Testing Requirements

The permit includes a requirement that the Permittee conduct performance testing on any specified emission unit when directed by the Division. Additionally, a written notification of any performance test(s) is required 30 days (or sixty (60) days for tests required by 40 CFR Part 63) prior to the date of the test(s) and a test plan is required to be submitted with the test notification. Test methods and procedures for determining compliance with applicable emission limitations are listed and test results are required to be submitted to the Division within 60 days of completion of the testing. Procedures for determining compliance with emission reduction requirements for SO_2 in Georgia Rule (uuu) are added to the list in Condition 4.1.3 for this renewal.

B. Specific Testing Requirements

1. Individual Equipment

Condition 4.2.1 requires a performance test for particulate matter emissions following 8760 operating hours, and allows the Permittee to request that the test be deferred for an additional 8760 operating hours if the results of the last test are less than half of the applicable emissions standard. This condition was modified from its original version to allow the testing deferment request.

Condition 4.2.2 was marked reserved because it referenced an initial performance test on the MHS that had already been performed.

Condition 4.2.3 requires ongoing (every 5 years) performance tests on the materials handling system to determine compliance with the emissions standards contained in 40 CFR 60 Subpart OOO.

Condition 4.2.4 requires initial, and ongoing (30-day rolling) performance tests for SO_2 reductions required for Georgia Rule (uuu), and was updated with the proper effective dates for the revised rule.

2. Equipment Groups (all subject to the same test requirements):

None applicable.

V. Monitoring Requirements

A. General Monitoring Requirements

Condition 5.1.1 requires that all continuous monitoring systems required by the Division be operated continuously except during monitoring system breakdowns and repairs. Monitoring system response during quality assurance activities is required to be measured and recorded. Maintenance or repair is required to be conducted in an expeditious manner.

B. Specific Monitoring Requirements

1. Individual Equipment:

Condition 5.2.1 requires continuous monitoring of opacity, and NO_X using COMS, and CEMS respectively on the outlets of the steam generating units. This condition was modified from its original version to allow the placement of the COMS upstream of the wet scrubbers, as well as to additionally require CEMS for monitoring SO_2 concentration in the scrubber and bypass stacks, and a continuous monitoring system for the number of FGD recycle pumps running. The effective date for SG03 was also updated according to the revised rule.

Condition 5.2.2 has been deleted. This condition originally required coal sulfur sampling and analysis to demonstrate compliance with sulfur limits in Georgia Rule (g), and 40 CFR 60 Subpart D. CEMs have been installed for future compliance with Georgia Rule (uuu) that will monitor SO_2 removal efficiency in the scrubber. CEMS in the scrubber and bypass stacks along with fuel usage allow calculation of lb SO_2/MMBtu fuel input.

Condition 5.2.3 requires analysis of any used oil to be burned in the steam generating units upon written request by the Division.

Condition 5.2.4 is modified to allow hourly monitoring of sulfur dioxide emissions using the new SO_2 CEMS rather than the coal bunker sulfur analysis.

Old Condition 5.2.14 from the original renewal permit 4911-207-0008-V-02-0 that required a daily VE walkthrough for non-controlled equipment was removed.

New Condition 5.2.14 is added to require pressure monitoring for the baghouses required by Georgia Rule (sss).

Condition 5.2.15 requires the facility to develop a Performance Management Plan, PMP, for the baghouses required by Georgia Rule (sss).

Condition 5.2.16 requires the facility to install and operate temperature monitoring in the inlet of the baghouses.

Condition 5.2.17 requires the Permittee to inspect the dust control systems on the material handling system daily, and to take corrective actions if problems are found. It was modified from its original version to be currently effective, as it has been more than 180 days since the initial startup of the MHS.

Condition 5.2.18 requires the Permittee to submit an updated CAM plan for units 1 and 2, after startup of the new flue gas desulfurization scrubbers required by Georgia Rule (sss). It originally required an updated CAM plan for units 3 and 4 as well. Updated CAM plans for units 3 and 4 are already contained in Conditions 5.2.8, and 5.2.9.

New Condition 5.2.19 requires continuous monitoring of the electrical output of generators driven by SG01, SG02, SG03, and SG04, and the rate of carbon injection in lbs/hr for each unit.

New Condition 5.2.20 requires the calculation of the minimum carbon injection rate for each steam generating unit.

New Conditions 5.2.21 and 5.2.22 require the continuous operation of the CEMS used to monitor the SO_2 emissions rate in the scrubber and bypass stacks, and data capture during at least 75% of all operating hours which are used to calculate hourly SO_2 emissions rates.

New Condition 5.2.23 requires that a unit specific SO_2 monitoring plan be submitted 45 days before implementation of the SO_2 CEMS required in Condition 5.2.1f. New Condition 5.2.24 requires certification of the SO_2 CEMS.

2. Equipment Groups (all subject to the same monitoring requirements):

None applicable.

C. Compliance Assurance Monitoring (CAM)

CAM requirements specified in Permit No. 4911-207-0008-V-01-0 are discussed in the initial Title V permit narrative for this permit. Please refer to this narrative.

CAM Permit Conditions
Condition 5.2.5 specifies the emissions units that are subject to Compliance Assurance Monitoring, (CAM).

Conditions 5.2.6 to 5.2.9 specify the CAM performance criteria for the monitoring of particulate emissions from the 4 steam generating units. Conditions 5.2.8 and 5.2.9 for SG03 and SG04 are modified to add a second indicator in the performance criteria of the number of FGD recycle pumps running for the CAM plan. The calculation of the 3-hour average opacity is now calculated based on data every 10 seconds rather than every 6 minutes.

Condition 5.2.10 requires the Permittee to maintain the particulate monitoring equipment required by conditions 5.2.6 – 5.2.9, and keep necessary parts required for routine repairs available.

Condition 5.2.11 requires the Permittee to keep all monitoring in continuous operation at all times that the emissions unit is operating.

Condition 5.2.12 requires proper operation of emissions units such that emissions are minimized. This Condition was modified from its original version to correct the reference to Condition 6.1.7.b and c, rather than Condition 6.1.7.c (i-iv).

Condition 5.2.13 requires the Permittee to notify the Division if the approved monitoring does not provide an indication of an excursion or exceedance, and to submit proposed modifications to the monitoring plan if such a situation occurs.

VI. Record Keeping and Reporting Requirements

A. General Record Keeping and Reporting Requirements

The Permit contains general requirements for the maintenance of all records for a period of five years following the date of entry and requires the prompt reporting of all information related to deviations from the applicable requirements. Records, including identification of any excess emissions, exceedances, or excursions from the applicable monitoring triggers, the cause of such occurrence, and the corrective action taken, are required to be kept by the Permittee and reporting is required on a quarterly basis.

Permit Conditions 6.1.3, and 6.1.4 were revised to incorporate the new extended reporting deadlines from 30 days after the reporting period to 60 days after the reporting period.

Permit condition No. 6.1.7 is modified from its original version to define excess emissions of NO_X to be based on an area-wide average or plant-wide average limit per Georgia Rule (jjj). Opacity, NO_X and SO_2 limits were moved from the Exceedances section to the Excess emissions section and the SO_2 limit for excess emissions was changed from a 30-day emissions rate to a 3-hour rolling rate because going forward, compliance will be demonstrated with output from the CEMS rather than a coal sulfur analysis. The effective date for SG03 was also updated according to the revised rule.

Old Permit Condition No. 6.1.7c.vi is removed because it referred to old Condition No. 5.2.14 that was removed in a previous amendment, and the remaining parts of the condition are renumbered starting at 6.1.7c.vi

Permit Condition No. 6.1.7c is modified (List Level iii, and iv) to add the number of FGD recycle pumps running to the conditions required for an excursion. Opacity must exceed 20 percent, and the number of FGD recycle pumps running must be less than 4 for an excursion.

Permit Condition No. 6.1.7c is modified (List Level vi) to add a new excursion for each occurrence when the temperature at the inlet of any bag house exceeds the filter bag design temperature.

Permit Condition No. 6.1.7c. is modified (List Level vii) by adding a new excursion for reporting instances that a weekly preventative maintenance check reveals a problem that is not resolved according to the Performance Management Plan.

Permit Condition No. 6.1.7c is modified (List Level viii) by adding a new excursion for reporting instances where daily inspections of the material handling system reveal visible emissions that are not corrected within 12 hours of the observation.

Permit Condition No. 6.1.7c. is modified (list level ix) by adding a new excursion for reporting a shortfall in the activated carbon injection rate.

B. Specific Record Keeping and Reporting Requirements

Record keeping and reporting requirements specified in Permit No. 4911-207-0008-V-02-0 are discussed in the initial Title V permit narrative for this permit. Please refer to this narrative.

Condition 6.2.1 is modified to add biodiesel, or biodiesel blends to the list of fuel oils for which usage records must be kept, and to require monthly records are retained for fuel burned, or received.

Condition 6.2.3 is modified to add ASTM D975 as an allowable fuel specification, and to add an additional test method, ASTM D1552, for the determination of sulfur content in No. 2 fuel oil. Permit Condition No. 6.2.10 is modified from its original version to expand the definition of excess emissions to include an area-wide limit, as well as a plant-wide average limit for recordkeeping, and reporting requirements.

Permit Conditions 6.2.12 was revised to incorporate the new extended reporting deadlines from 30 days after the reporting period to 60 days after the reporting period.

Old Condition 6.2.13 is deleted because this condition is not needed. The facility will be complying with a 1.2 lb/MMBtu SO_2 limit via the SO_2 CEMS installed in both the scrubber stacks (ST05, ST06, ST07, and ST08) and bypass scrubber stacks (ST01, ST02, ST03, and ST04). The CEMS data will allow the facility to calculate 3-hour rolling average SO_2 emissions rates and report any excess emissions. Subsequent conditions are renumbered.

New Condition 6.2.14 states the method to determine compliance with the sulfur reduction requirements in new Conditions 3.4.15 through 3.4.18.

New Condition 6.2.15 states the information that must be maintained for each 24-hour reporting period to determine compliance with limitations in new Conditions 3.4.15 through 3.4.18.

New Condition 6.2.16 states when the written reports of reportable emissions required in Condition 6.2.15 are due, and that reportable emissions are those that exceed the limits in Conditions 3.4.15 through 3.4.18. This Condition was revised to incorporate the new extended reporting deadlines from 30 days after the reporting period to 60 days after the reporting period.

New Conditions 6.2.17 specifies what information is required to be submitted if the facility does not obtain the minimum quantity of emissions data as required by the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants.**

New Condition 6.2.18 specifies the information that must be submitted within a signed statement for any periods for which SO_2 emissions data are not available.

New Condition 6.2.19 requires that results of each RATA shall be submitted to the Division within 60 days of the completion of the RATA.

New Conditions 6.2.20 through 6.2.22 require that the facility calculate and report their total actual emissions for the 10 years following the steam turbine upgrade projects to show compliance with the actual to predicted-actual emissions calculations made to justify avoidance of NSR review.

VII. Specific Requirements

A. Operational Flexibility

Other than the standard conditions (7.1.1, 7.2.1, 7.2.2), operational flexibility provisions have not been incorporated into this Title V Permit. The applicant did not include any alternative operating scenarios in the Title V Application or request any specific operational flexibility conditions.

B. Alternative Requirements

There are no alternative requirements that need to be included in the Title V Permit.

C. Insignificant Activities

Refer to http://airpermit.dnr.state.ga.us/GATV/default.asp for the Online Title V Application.

Refer to the following forms in the Title V permit application:

- Form D.1 (Insignificant Activities Checklist)
- Form D.2 (Generic Emissions Groups)
- Form D.3 (Generic Fuel Burning Equipment)
- Form D.6 (Insignificant Activities Based on Emission Levels of the Title V permit application)

D. Temporary Sources

None applicable. The facility may add temporary sources provided that the facility follows any necessary regulatory procedures for the operation of such sources, which may include amending the Title V Permit.

E. Short-Term Activities

As specified in the narrative for initial Title V Permit No. 4911-207-0008-V-01-0, Plant Scherer has the following short-term activities: painting for maintenance purposes, sand blasting for maintenance purposes, and asbestos removal in accordance with Georgia Rule 391-3-1-.02(9)(b)7. See Section D5 of the Title V application for a more complete description.

Other than asbestos removal, which is subject to Georgia Rule 391-3-1-.02(9)(b)7, these operations are not subject to any state or federal air quality requirements other than the general provisions of the Georgia Rules for Air Quality Control. The general provisions and the requirement to keep records of the frequency and duration of these activities has been included in Section 7.6 of the permit.

F. Compliance Schedule/Progress Reports

The facility is in compliance with all Air Quality Regulations. Therefore, no compliance schedule or progress reports are necessary.

G. Emissions Trading

This facility is not involved in any emission trading programs other than being a part of the Acid Rain Program.

H. Acid Rain Requirements

This facility is subject to the Acid Rain Requirements of Title IV. Condition 7.9.7 was modified from its original version, and updates for the Phase II NO_X averaging plan for years 2011 to 2015 for Emission Units SG01, SG02, SG03 and SG04 were made. The unit-specific alternative contemporaneous emission limitations have not changed in comparison to the 2006 to 2010 plan, but the unit-specific heat input limits have been updated for Emission Units SG01, SG02, SG03 and SG04 in this condition.

I. Stratospheric Ozone Protection Requirements

A description is specified in the narrative for initial Title V Permit No. 4911-207-0008-V-01-0. Please refer to this narrative.

J. Prevention of Accidental Releases

Prevention of Accidental Releases (from initial Title V Permit No. 4911-207-0008-V-01-0): Scherer Steam- Electric Generating Plant may store ammonia (conc. 20% or greater) and chlorine in excess of the applicable quantities to be subject to the accidental release prevention program. Please refer to the narrative for initial Title V Permit No. 4911-207-0008-V-01-0 for more information.

K. Pollution Prevention

There are no pollution prevention provisions incorporated into this Title V Permit.

L. Specific Conditions

There are no specific conditions associated with this permit renewal.

M. Clean Air Interstate (CAIR) Requirements

Condition 7.15.1 requires the facility to comply with all the applicable requirements in the CAIR permit application. The CAIR permit application is attached as part of this Title V Permit.

Condition 7.15.2 requires the facility to comply with the CAIR facility wide annual NO_X allowance allocations in accordance with 40 CFR 96 and Georgia Rule 391-3-1-.02(12).

The CAIR NO_X allowances have been determined by the Division for 2011. The CAIR allowances are not unit specific and the allowances are awarded for the entire facility for each calendar year. No allowances are specified after 2011 because the CAIR rule is being replaced by the Cross State Air Pollution Rule (CSAPR) starting in 2012. CSAPR will be implemented directly by the EPA under the Federal Implementation Plan (FIP).

VIII. General Provisions

Generic provisions have been included in this permit to address the requirements in 40 CFR Part 70 that apply to all Title V sources, and the requirements in Chapter 391-3-1 of the Georgia Rules for Air Quality Control that apply to all stationary sources of air pollution.

Permit Condition 8.14.1 was revised to incorporate the new extended reporting deadlines from 30 days after the reporting period to 60 days after the reporting period.

Condition 8.17.2 was marked as State Only Enforceable in Permit Amendment No. 4911-207-0008-V-02-4.

Addendum to Narrative

The public notice was published in the *Monroe County Reporter* on September 21, 2011. The 30-day public comment period expired October 21, 2011. Comments were received from Georgia Power on October 24, 2011, and from Greenlaw, The Southern Environmental Law Center, and the Sierra Club collectively on October 21, 2011. Each comment is printed below, followed by a discussion of the comment and any changes made to the permit as a result.

Georgia Power Comments

1. **Condition 1.3** – Georgia Power requests to change the Overall Facility Process Description so that it accurately describes the current processes and controls at the facility.

   Plant Scherer burns fossil fuel to generate electricity. This facility includes four steam electric generating units which primarily burn coal. ~~Currently, steam generating units SG01 and SG02 exhaust through separate liners of one 1000-foot stack, and steam generating units SG03 and SG04 exhaust through separate liners of a second 1000-foot stack.~~ Wet limestone Flue Gas Desulfurization (FGD) scrubbers are being installed on Steam Generating Units SG01, SG02, ~~SG03,~~ and SG04. An FGD scrubber is currently installed on Steam Generating Unit SG03. ~~Two~~ An 870-foot wet stack~~s~~ ~~(870-foot stack~~ for SG01 and SG02, ~~and 847-foot stack for SG03 and SG04)~~ with separate liners for each unit, ~~are~~ is being installed. An 847-foot wet stack for SG03 and SG04, with separate liners for each unit, is currently installed. When the FGD scrubbers are operational, during normal operation the units will exhaust through the wet stacks. There are some operations when it will be necessary to bypass the scrubber. In these cases the units will exhaust through the existing 1000- foot stacks.

   Response: The Division agrees, and has revised this condition accordingly.

2. **Condition 3.3.6** – Georgia Power requests removal of this condition as the requirement is already stated in Condition 3.4.5.

   Response: The Division will remove the opacity limit on the coal handling system from Condition 3.4.5, and leave Condition 3.3.6 as-is. Condition 3.3.6 lists the citation for the opacity limit applicable to the Coal Handling System for both Georgia Rule(n) and 40 CFR 60 Subpart Y.

3. **Condition 4.2.2** – Georgia Power requests removal of this condition as the initial performance testing on the Materials Handling System was already completed and submitted to Georgia EPD on April 11, 2011.

   Response: The Division agrees, and has removed this condition.

4. **Condition 4.2.4** – Georgia Power requests to correct the reference to Condition 3.4.17. The current language refers to this condition as "3,4,17".

   Response: The Division agrees, and has revised this condition accordingly.

5. **Condition 5.2.12** – Georgia Power requests to correct the reference to Condition 6.1.7c(i. to iv.). Condition 5.2.12 refers to an excursion and an exceedance; therefore, the reference should be 6.1.7b and c.

   Response: The Division agrees, and has revised this condition accordingly.

6. **Condition 5.2.17** – Georgia Power requests to remove the first sentence of this condition. This condition is currently effective because the MHS has been operational for more than 180 days from initial startup.

   Response: The Division agrees, and has revised this condition accordingly.

7. **Condition 5.2.18** – Georgia Power requests to remove FGD3 and FGD4 from this condition as the CAM plan for Units 3 and 4 was submitted to Georgia EPD on June 22, 2011. The results of the CAM plan for Units 3 and 4 are already incorporated into this permit renewal in Conditions 5.2.8 and 5.2.9.

   Response: The Division agrees, and has revised this condition accordingly.

8. **Condition 6.2.1** – Georgia Power requests to change the language in this condition such that the recordkeeping requirements for sawdust and biomass are accurately reflected.

   State Only Enforceable Condition.
   The Permittee shall retain monthly records of all fuel burned (except c and d below which shall be monitored on an as received basis), in the steam generating units with Emission Unit IDs SG01, SG02, SG03, and SG04, for five years after the date and year of record. The records shall be available for inspection or submittal to the Division, upon request, and contain the following: [391-3-1-.02(6)(b)1(i)]

   a. *Quantity (tons) of coal burned.*

   b. *Aggregate total quantity (gallons) of distillate oil, No. 2 fuel oil, biodiesel, biodiesel blends, or very low sulfur oil burned.*

   c. *Quantity (tons) of sawdust received.*

   d. *Quantity (tons) of biomass received.*

   e. *Quantity (gallons) of used oil burned.*

   f. *Quantity (tons) of coal-derived synthetic fuel received.*

   Response: The Division agrees, and has revised this condition accordingly. Condition 6.2.1 is also updated to require the monitoring of the quantity of coal derived synthetic fuel on an as-received basis each month.

9. **Insignificant Activity Checklist** – Georgia Power requests that the following quantities are changed from "1" to "X" since the activities cannot be defined by a quantifiable unit.

   Mobile Sources Activity No. 1
   Combustion Equipment Activity Nos. 1 and 3
   Trade Operations Activity No. 1
   Maintenance, Cleaning, and Housekeeping Activity No. 5
   Industrial Operations Activity No. 3

   Response: The Division agrees, and has revised Attachment B accordingly.

10. **Conditions 3.4.14, 3.4.15, 4.2.4, 5.2.1f, and 6.1.7b(iii),** – Georgia Power requests that the effective dates for Georgia Rules 391-3-1-.02(2)(sss) and 391-3-1-.02(2)(uuu) for Steam Generating Unit SG03 are updated to July 1, 2011 to reflect the change in the revised rule.

    Response: The Division agrees, and has revised these conditions accordingly.

11. **Conditions 6.1.3, 6.1.4, 6.2.12, 6.2.16, and 8.14.1** – Georgia Power requests to update the deadlines associated with Title V air permit periodic reporting and annual compliance certifications. As per guidance from the Georgia EPD, Title V renewal permits will incorporate this change, which extends the reporting deadline from 30 days after the reporting period to 60 days after the reporting period.

    Response: The Division agrees, and has revised these conditions accordingly.

Southern Environmental Law Center Comments

Please refer to EPD's permit file for the entire copy of the comments received (33 pages) from Southern Environmental Law Center, and GreenLaw.

1. **Background**

   Response: Condition 3.4.14 and 3.4.19 state the requirements of Georgia Rule 391-3-1-.02(2)(sss) and Georgia Rule 391-3-1-.02(2)(uuu), respectively, for steam generating unit SG01, SG02, SG03 and SG04. The wordings in these conditions come straight from the rule. Therefore, EPD will not modify this language in Conditions 3.4.14 and 3.4.19.

2. **Regulatory Framework**

   Response: Comment so noted. Regarding the comment that "Permitting authorities should…issue renewed permits prior to expiration of the existing permit," EPD notes that, provided a timely renewal application is submitted, the Permit is not null and void. Expiration of a permit occurs when a Permittee fails to submit a timely application, and EPD fails to issue a renewal permit within 5 years of issuance of existing permit.

Georgia Rule 391-3-1-.03(10)(e)1.(ii) states that "Except as provided under the initial transition plan or under regulations promulgated under Title IV of the federal Clean Air Act, the Director shall take final action on each permit application (including request for permit modification or renewal) within 18 months after receiving a complete application".

3. The Draft Permit is Incomplete

a. Megawatt Capacity and Heat Input Rates

Response: Maximum heat input rates for each of the four steam generating units were included in the narrative for the initial Title V Permit No. 4911-207-0008-V-02-0. The updated table is as follows:

Emission Unit ID No.	Emission Unit Description	Max. Heat Input Capacity (MMBtu/hr)	Fuel Burning Configuration
SG01	Steam Generator Unit 1	10052*	Tangentially-fired
SG02	Steam Generator Unit 2	10070*	Tangentially-fired
SG03	Steam Generator Unit 3	9771	Tangentially-fired
SG04	Steam Generator Unit 4	9653	Tangentially-fired

*Projected – Turbine upgrade project for these units not completed yet.

The maximum heat input rates for each of the four steam generating units were included by the facility in this Title V Renewal Application No. 19764, which is readily available on EPD's website at http://airpermit.dnr.state.ga.us/GATV/GATV/default.asp.

The megawatt capacity can vary depending on a number of factors for each unit. There is no regulatory requirement in 40 CFR 70 to include the maximum heat input rate and megawatt capacity in the Title V Operating Permit.

b. Unclear and Incomplete Permit Terms

Response: The Compliance Assurance Monitoring (CAM) requirements developed per 40 CFR 64 are incorporated in Permit Conditions 5.2.5 through 5.2.13 in this Title V Permit. There is no requirement in 40 CFR 70 to attach the CAM plan to the Title V Permit. Also, the CAM plan for Title V Renewal Application No. 19764 is electronically available on EPD's website at http://airpermit.dnr.state.ga.us/GATV/GATV/default.asp, under Section A8, Attached Electronic Documents. The CAM plan is part of the Title V Application submitted by Georgia Power.

The Acid Rain application (Attachment D) is attached as part of the Title V permit in condition 7.9.8. The CAIR application (Attachment E) is attached as part of the permit in Condition 7.15.1. The CAIR application was submitted and available for public viewing in our office files. The application was not reviewable in the online version. EPD intends to provide more complete draft permit information on-line in the future as our resources improve.

EPD appreciates the concern regarding the narrative referencing to older narratives, although said narratives and permits are available on our website at www.georgiaair.org. To address the concerns in the future, EPD will be providing more substantial Title V renewal narratives, to reduce or eliminate the need to review older permits and narratives.

4. EPD Improperly Determined PSD Applicability for Turbine Upgrades

a. Legal Background

b. EPD and GPC Improperly Combined Pollution Control Projects with the Turbine Upgrade Project in Determining Whether a Significant Emissions Increase of SO_2 and NO_X Would Occur.

c. GPC and EPD Failed to Conduct a Proper Analysis of Whether a Significant Net Emissions Increase of SO_2 or NO_X would occur as a Result of the Turbine Upgrades.

Response: Current PSD regulations allow a baseline actual-to-projected actual applicability test for projects that only involve existing emissions units. The definition of projected actual emissions in Georgia Rule 391-3-1-.02(7)(a)2.(ii)(I) means *the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the five years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.* Nowhere in the rule is it stated that projected actual emissions must be adjusted upward to ignore the installation of pollution control equipment.

The Division's review shows that the turbine upgrade projects for Units 1, 2, 3 and 4 will not result in emissions increases for NO_X, SO_2, PM, PM_{10}, and will not result in significant emission increases for CO and VOC (which is the first step: the baseline-actual-to-projected-actual NSR/PSD applicability step). Therefore, netting (which is the second step of the NSR/PSD applicability test) is only applicable if the turbine upgrade project may result in significant emissions increase above the respective PSD major modification thresholds for any regulated pollutant, which is not in this case. Therefore, the Division does not agree with the commentator that the turbine upgrade projects for Units 1, 2, 3 and 4 will result in significant emissions increases for NO_X and SO_2.

Also, the 1990 EPA New Source Review Workshop Manual is a draft guidance document, and are of limited use and relevance in this case. It pre-dates the federal NSR reform rules, and Georgia's PSD rules based on the NSR reforms. Georgia Air Rules 391-3-1-.02(7) are not identical to those in 40 CFR 52.21.

To address the commentators' concerns, the Division has added Conditions 6.2.20, 6.2.21, and 6.2.22 to require record keeping and reporting of actual emissions that are pertinent to this modification (i.e. the turbine upgrade projects for Units 1, 2, 3 and 4) in accordance with Georgia Rule 391-3-1-.02(7)(b)15.(i). These conditions will require the facility to record, maintain and report actual emissions that are pertinent to this modification that justify avoidance of NSR/PSD review and document accuracy of the baseline-actual-to-projected-actual emissions calculations and explain any increases reported.

5. Emission Standards and Compliance

a. Heat Inputs

Response: There is no regulatory requirement in 40 CFR 70 to include the maximum heat input rate for each steam generating unit as an enforceable condition in the Title V Operating Permit. The emissions from the steam generating unit are limited by the design heat input capacity of the unit, and the facility is required to comply with the emission limits in Section 3.0 of this Title V Permit.

b. Fuel Flexibility

Response: There is no regulatory requirement in 40 CFR 70 to warrant a limit on the usage of fuel in this Renewal Title V Operating Permit.

The commenter is incorrect in stating that the definition of biomass allows facility to be able to fire municipal solid waste in the steam generating units. Permit Condition 3.2.1c. explicitly states that the definition of biomass does not include municipal solid waste. Biomass is specifically defined as paper, vegetative matter, or wood chips, and specifically excludes municipal solid waste in Condition 3.2.1c.

Also, Permit Condition 6.2.1 requires the facility to maintain usage records for all types of fuels that are fired, including biomass. Permit Condition 5.2.1 requires the facility to install and operate Continuous Emissions Monitoring Systems (CEMS) for NO_X emissions and install and operate Continuous Opacity Monitoring Systems (COMS) for visible emissions on the steam generating units. These continuous monitoring systems will ensure that the facility can comply with the opacity and NO_X emissions limits in Section 3.0 of the permit. Compliance with the PM limit is done via annual performance tests. No additional monitoring and recordkeeping are required under 40 CFR 70 requirements.

Generally, the term "peak load" is understood as the electric generating capacity required by a utility to respond to a maximum level of energy demand over a specified period of time. The term "flame stabilization" is relevant to situations where flame performance in the primary fuel burner becomes unstable and the use of additional igniters or lighters are used to sustain proper combustion.

The term startup is defined in Condition 3.2.2 for burning used oil. Per Georgia Rule 391-3-1-.01(jjj), the term shutdown means the cessation of the operation of a source or facility for any purpose, and this definition will be added in Condition 3.2.2.

c. Particulate Matter

i. The PM Limit Should be Significantly Lowered in Order to Abate the Facility's Contribution to Nonattainment of the PM2.5 NAAQS.

Response: This is not a PSD permit and there is no regulatory requirement in 40 CFR 70 to impose new PM, PM_{10}, or $PM_{2.5}$ emission limit in this Title V Operating Permit.

ii. Coarse and Fine Particulate Pollution Should be Limited and Monitored Separately.

Response: This facility is not currently subject to any $PM_{2.5}$ emissions standards or limits (applicable requirements). Permit Condition 3.3.2 subjects the four steam generating units to a particulate matter (PM) limit of 0.10 lb/MMBtu heat input, and the method of compliance is via a performance test using Method 5 or Method 17, as applicable, as listed in Condition 4.1.3f. Because PSD review was not triggered, there is no justification for adding separate $PM_{2.5}$ limits. Should a modification be made at a later date that is found to trigger PSD review for $PM_{2.5}$, separate $PM_{2.5}$ limits may be incorporated into the Permit.

This renewal application did not trigger any requirement to include new $PM_{2.5}$ emission limit.

iii. The Frequency of PM Testing Must Be Increased.

Response: There is no regulatory requirement in 40 CFR 70 to require this facility to install PM CEMS on Steam Generating Units 1, 2, 3 and 4. PM testing requirements in Condition 4.2.1 and the operation of the Continuous Opacity Monitoring Systems (COMS) are sufficient monitoring requirements to ensure this facility will be able to comply with the PM and opacity emissions limits.

d. NO_X and SO_2

i. The Draft Permit Must be Revised to Incorporate Revisions to Rules (sss) and (uuu).

Response: The Division agrees and the changes to the applicable Permit Conditions have been made accordingly.

ii. The Draft Permit Must be Revised to Include Cross-State Air Pollutions Rule Requirements.

Response: The CAIR NO_X allowances have been determined by the Division for 2012 and 2013, and they are listed in Condition 7.15.2. The Cross State Air Pollution Rule (CSAPR) was stayed by the federal court on December 30, 2011. Therefore, the Clean Air Interstate Rule (CAIR) will continue to apply because CSAPR was stayed.

iii. The Draft Permit's SO_2 Monitoring and Compliance Provisions Must be Revised to be Consistent with the new 1-hr SO_2 NAAQS

Response: There is no regulatory requirement to impose a new SO_2 emission limit in this Title V Operating Permit.

iv. The Permit Should Clearly Require SO_2 CEMS Operation During All Periods of Operation except CEMS Breakdown and Repair.

Response: SO_2 CEMS are required to run during all periods of operation by the Part 75 rules, including startup, shutdown, malfunction, and during emergency conditions. The Division allows exceptions including periods of CEMS breakdown, repairs, calibration checks, and zero and span adjustments. It should be noted that during calibration checks, zero and span adjustments, it is impossible to measure stack emissions by the very nature of these daily calibration tests, as calibration gases must be run through the CEMS to make sure that they are working properly. Data collected are not required during startup, shutdown, malfunction, black start, preventive maintenance, performance testing or RATA on the bypass stack, and Division approved control equipment R&D because they are not indicative of the scrubber control efficiency and the SO_2 reduction limits for Georgia Rule(uuu) do not apply during such periods.

6. Excess Emissions

a. Condition 8.14.4 should not include an Affirmative Defense.

Response: The excess emissions provisions come directly from Georgia Rule 391-3-1-.02(2)(a)7.

b. If an affirmative defense is retained, it must be revised to state that all excess emissions are violations and to retain the availability of injunctive relief.

Response: Condition 8.14.4 in this Title V Renewal Permit directly comes from Georgia Rule 391-3-1-.02(2)(a)7.(i). This rule has been an EPA-approved part of the Georgia SIP since 1979 and the validity of this rule has been specifically upheld by the courts. See e.g., Sierra Club v. Ga. Power Co., 443 F.3d 1346 (11th Cir. 2006) (recognizing the rule as a continuous part of the Georgia SIP). Because it is part of the Georgia SIP, it is entirely appropriate to simply repeat the rule language verbatim in the Plant Scherer Title V permit. The comment's citations appear to be referring to EPA guidance documents regarding the submission of new SIP provisions that regulate startup, shutdown, and malfunction events; however, EPA has specifically acknowledged that such guidance was not intended to affect the validity of existing, approved SIP provisions addressing these events. Therefore, Condition 8.14.4 is appropriate as written.

c. If an affirmative defense is retained, it must be revised to provide objective criteria that will allow for practical enforceability.

i. Vague and undefined terms must be replaced with specific and objective operational requirements.

ii. The permit must include separate criteria for malfunctions.

Response: Please refer to EPD's response to Southern Environmental Law Center Comment 5b.

Per Georgia Rule 391-3-1-.01(nn), malfunction means mechanical and/or electrical failure of a process, or of air pollution control process or equipment, resulting in operation in an abnormal or unusual manner. Georgia Rule 391-3-1-.02(2)(a)7 and Condition 8.14.4 do not preclude the use of more specific criteria.

d. Condition 8.14.4 must be revised to address National Emissions Standards for Hazardous Air Pollutants.

Response: Georgia Rule 391-3-1-.02(2)(a)7.(iii) does not mention National Emissions Standards for Hazardous Air Pollutants (NESHAPS) in the rule.

Georgia Rule 391-3-1-.02(2)(a)7 shall apply only to those sources which are <u>not</u> subject to any requirement under Georgia Rule 391-3-1-.02(8) – New Source Performance Standards or any requirement of 40 CFR, Part 60, as amended concerning New Source Performance Standards.

7. Coal Handling System

Response: There is no regulatory requirement in 40 CFR 70 to require the facility to install enclosures, other control devices, and specific dust suppression measures.

Fugitive emissions from the coal handling system must meet the 20 percent opacity limit in Georgia Rule (n). The facility must comply with Condition 6.2.6 that requires the facility to maintain a record of all actions taken in accordance with Condition 3.4.4 to suppress fugitive dust from the coal handling system (Source Code: CHS) and the ash handling system (Source Code: AHS).

8. Greenhouse Gas Monitoring and Reporting

Response: Pages 52-53 of the PSD and Title V Permitting Guidance document cited by the commenter states as following

"It is important to note that GHG reporting requirements for sources established under EPA's final rule for the mandatory reporting of GHGs (40 CFR Part 98: Mandatory Greenhouse Gas Reporting, hereafter referred to as the "GHG reporting rule") are currently ***not included in the definition of applicable requirement in 40 CFR 70.2 and 71.2.*** *Although the requirements contained in the GHG reporting rule currently are not considered applicable requirements under the title V regulations, the source is not relieved from the requirement to comply with the GHG reporting rule separately from compliance with their title V operating permit. It is the responsibility of each source to determine the applicability of the GHG reporting rule and to comply with it, as necessary. However, <u>since the requirements of the GHG reporting rule are not considered applicable requirements under title V, they do not need to be included in the title V permit.</u>"*

There is no regulatory requirement in 40 CFR 70 to include the Mandatory Greenhouse Gas Reporting Requirement in this Title V Operating Permit.

9. Hazardous Air Pollutants

Response: Since the permit will not be final until after the effective date of the EGU Utility MACT, Condition 3.3.8 is added to include the general requirements for the EGU MACT as applicable.

Permit Condition 8.11.1 is changed to specify a 3 year term per Georgia Rule 391-3-1-.03(10)(e)6(i)(I)

http://www.epa.gov/region4/air/permits/georgia.htm

Region 4: Proposed Title V Permits

Last updated on 05/18/2012

You are here: EPA Home Region 4 Air Air Permits Proposed Title V Permits Georgia

Georgia Proposed Title V Permits

The following permits have been submitted to EPA Region 4 as Proposed Title V permits. While EPA has the right to a 45-day review period for all Proposed Title V permits, EPA Region 4 targets only a subset of these permits for comprehensive review. To find out which permits have been targeted for EPA Region 4 review, please contact the Region 4 staff person(s) listed at the bottom of this page.

Title V Permits Undergoing Sequential Review*

State	County	Source Name	PA Permit Number	45-Day Review Ends (sequential)	Petition Deadline
GA	Monroe	Georgia Power Cpmpany - Plant Scherer	4911-207-0008-V-03-0	4/14/2012	6/13/2012
GA	Madison	Transcontinental Gas Pipe Line Corp. - Station 130	4922-195-0015-V-03-0	4/14/2012	6/13/2012

Title V Permits Undergoing Parallel Review**

State	County	Source Name	PA Permit Number	45-Day Review Ends (parallel)	Petition Deadline
GA	DeKalb	CITGO Doraville Terminal	5171-089-0127-V-03-0	3/4/2012	6/11/2012
GA	Fulton	Owens Corning Insulating Systems, LLC	3296-121-0021-V-02-4	3/9/2012	6/15/2012
GA	Carroll	Southwire Company - Carrollton Utility Products Plant	3357-045-0052-V-04-0	3/23/2012	6/25/2012
GA	DeKalb	Seminole Road MSW Landfill	4953-089-0299-V-02-2	3/23/2012	7/2/2012

* **Sequential Review** means the EPA 45-day review period does not begin until the 30-day public comment period ends. The deadline for the public to petition EPA is 60 days after the EPA 45-day review period ends.

** **Parallel Review** means the EPA 45-day review period runs concurrently with the 30-day public comment period and ends **no earlier** than 15 days after the end of the public comment period. The deadline for the public to petition EPA is 60 days after the EPA 45-day review period ends, calculated as if the Title V permit was under sequential review (i.e., the petition deadline will be the same regardless of whether Parallel or Sequential Review is followed.)

For information about the contents of this page please contact James Purvis.

EXHIBIT
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Georgia Department of Natural Resources PF
Environmental Protection Division • Air Protection Branch
4244 International Parkway • Suite 120 • Atlanta • Georgia 30354
404/363-7000 • Fax: 404/363-7100
Noel Holcomb, Commissioner
Carol A. Couch, Ph.D., Director

MAR 1 2 2009

Mr. Michael E. Wilder
Manager, Air Programs – Environmental Affairs
Georgia Power Company
241 Ralph McGill Blvd. NE, Bin 10221
Atlanta, Georgia 30308

Re: Application Type: Significant Modification with Construction, No. 18835, dated March 10, 2009
Scherer Steam – Electric Generating Plant, Juliette, AIRS No.: 4-13-207-00008

Dear Mr. Wilder:

This is to acknowledge receipt of your Air Quality Permit application. After our initial review of the information and technical data in this application, we will notify you if more information is needed to complete the application so that we can finish our review.

If your company qualifies as a small business (generally those with less than 100 employees), you may contact our Small Business Technical Assistance Program at 404/362-4842 for free and confidential permitting assistance.

To track the status of the air quality permit application, log on to Georgia Environmental Protection Division's *Georgia Environmental Connections Online* (GECO) at the web address http://airpermit.dnr.state.ga.us (registration required) and follow the online instructions.

If you have any questions or concerns regarding your application, please contact me at (404) 362-4841 or via e-mail at anna_aponte@dnr.state.ga.us. Any written correspondence should reference the above application number that has been assigned to this application and the facility's AIRS number.

Sincerely,

Anna C. Aponte

Anna C. Aponte
Environmental Engineer
Stationary Source Permitting Program

EXHIBIT
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State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch

Stationary Source Permitting Program
4244 International Parkway, Suite 120
Atlanta, Georgia 30354
404/363-7000
Fax: 404/363-7100

SIP AIR PERMIT APPLICATION

RECEIVED
MAR 11 2009
AIR PROTECTION BRANCH

EPD Use Only

Date Received: MAR 11 2009 Application No. 18835

FORM 1.00: GENERAL INFORMATION

1. Facility Information

Facility Name: Scherer Steam-Electric Generating Plant
AIRS No. (if known): 04-13- 207 - 00008
Facility Location: Street: 10986 Highway 87
City: Juliette Georgia Zip: 31046 County: Monroe

2. Facility Coordinates

Latitude: 33° 3' 30" **NORTH** Longitude: 83° 48' 26" **WEST**
UTM Coordinates: ______ **EAST** ______ **NORTH** **ZONE** ______

3. Facility Owner

Name of Owner: Georgia Power Company
Owner Address Street: 241 Ralph McGill Blvd
City: Atlanta State: Georgia Zip: 30308

4. Permitting Contact and Mailing Address

Contact Person: Mike Wilder Title: Manager - Air Programs
Telephone No.: 404-506-7757 Ext. ______ Fax No.: 404-506-1499
Email Address: mewilder@southernco.com
Mailing Address: Same as: Facility Location: ☐ Owner Address: ☒ Other: ☐
If Other: Street Address: ______
City: ______ State: ______ Zip: ______

5. Authorized Official

Name: Charles H. Huling Title: Vice President, Environmental Affairs
Address of Official Street: 241 Ralph McGill Blvd
City: Atlanta State: Georgia Zip: 30308

This application is submitted in accordance with the provisions of the Georgia Rules for Air Quality Control and, to the best of my knowledge, is complete and correct.

Signature: Charles H. Huling Date: March 10, 2009

6. **Reason for Application: (Check all that apply)**

☐ New Facility (to be constructed)

☒ Existing Facility (initial or modification application)

☐ Permit to Construct

☐ Permit to Operate

☐ Change of Location

☒ Permit to Modify Existing Equipment: Affected Permit No.: 4911-207-0008-V-02-0 *

☐ Revision of Data Submitted in an Earlier Application

Application No.: ______

Date of Original Submittal: ______

** No changes to Permit No. 4911-207-0008-V-02-0 and amendments are necessary as a result of this modification.*

7. **Permitting Exemption Activities (for permitted facilities only):**
Have any exempt modifications based on emission level per Georgia Rule 391-3-1-.03(6)(i)(3) been performed at the facility that have not been previously incorporated in a permit?
☒ **No** ☐ **Yes, please fill out the SIP Exemption Attachment** (See Instructions for the attachment download)

8. **Has assistance been provided to you for any part of this application?**
☒ **No** ☐ **Yes, SBAP** ☐ **Yes, a consultant has been employed or will be employed.**
If yes, please provide the following information:
Name of Consulting Company: ______
Name of Contact: ______
Telephone No.: ______ Fax No.: ______
Email Address: ______
Mailing Address: Street: ______
City: ______ State: ______ Zip: ______
Describe the Consultant's Involvement:

9. **Submitted Application Forms:** Select only the necessary forms for the facility application that will be submitted.

No. of Forms	Form
1	2.00 Emission Unit List
1	2.01 Boilers and Fuel Burning Equipment
	2.02 Storage Tank Physical Data
	2.03 Printing Operations
	2.04 Surface Coating Operations
	2.05 Waste Incinerators (solid/liquid waste destruction)
	2.06 Manufacturing and Operational Data
	3.00 Air Pollution Control Devices (APCD)
	3.01 Scrubbers
	3.02 Baghouses & Other Filter Collectors
	3.03 Electrostatic Precipitators
1	4.00 Emissions Data
	5.00 Monitoring Information
	6.00 Fugitive Emission Sources
	7.00 Air Modeling Information

10. **Construction or Modification Date**
Estimated Start Date: October 2010

11. **If confidential information is being submitted in this application, were the guidelines followed in the "Procedures for Requesting that Submitted Information be treated as Confidential"?**

☒ No ☐ Yes

12. New Facility Emissions Summary

Criteria Pollutant	New Facility	
	Potential (tpy)	Actual (tpy)
Carbon monoxide (CO)		
Nitrogen oxides (NOx)		
Particulate Matter (PM)		
PM <10 microns (PM10)		
PM <2.5 microns (PM2.5)		
Sulfur dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Total Hazardous Air Pollutants (HAPs)		
Individual HAPs Listed Below:		

13. Existing Facility Emissions Summary[1]

Criteria Pollutant	Current Facility[2]		After Modification[3]	
	Potential[4] (tpy)	Actual (tpy)	Potential[4] (tpy)	Actual (tpy)
Carbon monoxide (CO)	> 100	657.0	> 100	673.3
Nitrogen oxides (NOx)	> 100	4,152.5	> 100	3,524.5
Particulate Matter (PM), including condensables	> 100	733.6	> 100	24.6
PM <10 microns (PM10), including condensables	> 100	516.8	> 100	17.9
PM <2.5 microns (PM2.5), including condensables	> 100	267.1	> 100	10.2
Sulfur dioxide (SO_2)	> 100	19,825.8	> 100	1,344.6
Volatile Organic Compounds (VOC) [5]	< 100	77.5	> 100	79.5
Total Hazardous Air Pollutants (HAPs)	> 25	> 25	> 25	> 25
Individual HAPs Listed Below: (See Title V application dated 12/12/2008 for information on individual HAPs)				

14. 4-Digit Facility Identification Code:

[1] Existing Facility Emissions Summary includes emissions for Unit SG03 only. No changes in Units SG01, SG02, and SG04 are expected as a result of this project.

[2] Current Facility actual emissions estimates represent baseline actual emissions from October 2005 through September 2007.

[3] After Modification actual emissions estimates represent projected actual emissions from January through December 2017.

[4] The major source status for all pollutants will remain the same before and after the project.

[5] The potential VOC emissions for Unit SG03 currently are slightly less than 100 tons per year. However, the current facility-wide potential emissions of VOC are greater than 100 tons per year and the major source status of Plant Scherer for VOC will not change as a result of this project.

SIC Code: 4911 SIC Description: Electric Services

NAICS Code: 221119 NAICS Description: Other Electric Power Generation

15. Description of general production process and operation for which a permit is being requested. If necessary, attach additional sheets to give an adequate description. Include layout drawings, as necessary, to describe each process. References should be made to source codes used in the application.

Georgia Power proposes to replace the high pressure section of the Unit 3 steam turbine with a new, more efficient high pressure section that will allow for increased steam flow. A steam turbine consists of blades or buckets attached to a rotating shaft. The shaft and blades are surrounded by a metal casing in which stationary blades and nozzles are mounted. The turbines at Plant Scherer are divided into three sections – high pressure, intermediate pressure, and low pressure. Steam from the boiler is directed through the stationary nozzles and blades and through each section of moving blades in order to transform the energy from the steam into energy used to turn a generator to produce electricity. The project proposed involves replacing the existing high pressure rotor and inner shell assembly, including the attached blades, with a more efficient design. The purpose of the project is to improve the efficiency of the high pressure section of the turbine (i.e. after the project, the turbine will be able to generate more electricity from the same amount of coal). The project will also increase the turbine's maximum steamflow capacity which will enable the unit to increase heat input as well. The combined effect of the increase in efficiency and the increase in maximum steamflow capacity of the turbine will allow Plant Scherer Unit 3 to increase its maximum generating capacity by a total of 35 megawatts (MW). The increased output resulting from this project will help offset some of the increase in station service (electricity required to run the plant itself) needed to operate the flue gas desulfurization system ("scrubber") that Plant Scherer plans to install simultaneously with this project. The turbine project will not involve any physical changes to the boiler.

16. Additional information provided in attachments as listed below:

Attachment A - __________
Attachment B - __________
Attachment C - __________
Attachment D - __________
Attachment E - __________
Attachment F - __________

17. Additional Information: Unless previously submitted, include the following two items:

☐ Plot plan/map of facility location or date of previous submittal: Title V application dated 12/12/2008

☐ Flow Diagram or date of previous submittal: Title V application dated 12/12/2008

Facility Name: Scherer Steam-Electric Generating Plant **Date of Application:** February 23, 2009

FORM 2.00 – EMISSION UNIT LIST

Emission Unit ID	Name	Manufacturer and Model Number	Description
SG03	Steam Generator Unit 3	Alstom Power, Inc (formerly Combustion Engineering) CCRRD-1530382.	Steam source for turbine generator used to generate electricity.

Facility Name: Scherer Steam-Electric Generating Plant **Date of Application:** February 23, 2009

FORM 2.01 – BOILERS AND FUEL BURNING EQUIPMENT

Emission Unit ID	Type of Burner	Type of Draft[1]	Design Capacity of Unit (MMBtu/hr Input)	Percent Excess Air	Dates		Date & Description of Last Modification
					Construction	Installation	
SG03	Tangentially-fired	Balanced	9771	15	1986	1987	Not Applicable (N/A)

[1] This column does not have to be completed for natural gas only fired equipment.

Facility Name: Scherer Steam-Electric Generating Plant

Date of Application: February 23, 2009

FUEL DATA

Emission Unit ID	Fuel Type	Potential Annual Consumption				Hourly Consumption		Heat Content		Percent Sulfur		Percent Ash in Solid Fuel	
		Total Quantity		Percent Use by Season									
		Amount	Units	Ozone Season May 1 - Sept 30	Non-ozone Season Oct 1 - Apr 30	Max.	Avg.	Min.	Avg.	Max.	Avg.	Max.	Avg.
SG03	Coal, subbituminous	4,027,084	tons	42	58	564	N/A	N/A	8663	N/A	N/A	N/A	N/A
SG03	Coal, bituminous	2,746,978	tons	42	58	385	N/A	N/A	12,700	N/A	N/A	N/A	N/A
SG03	No. 2 fuel oil	2.5	million gal	42	58	5034	N/A	N/A	138500	N/A	N/A		

Fuel Supplier Information

Fuel Type	Name of Supplier	Phone Number	Supplier Location			
			Address	City	State	Zip

Facility Name: Scherer Steam-Electric Generating Plant **Date of Application:** February 23, 2009

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
SG03	EP03, BH03, SCR3, FGD3	ST03	CO	194.5		673.3	> 100	AP-42
			NOx	1,018.0		3,524.5	> 100	Emission factors[1], CEMS, permit limit[2]
			PM including condensables	7.1		24.6	> 100	Stack test, permit limit, EPRI[3], BART method[4], and AP-42[5]
			PM10 including condensables	5.2		17.9	> 100	
			PM2.5 including condensables	3.0		10.2	> 100	
			SO_2	388.4		1,344.6	> 100	CEMS, permit limit
			VOC	22.9		79.5	> 100	AP-42

[1] Actual emissions estimates based on ozone season only operation of the SCR at 0.07 lb/mmBtu. Non-ozone season actual NOx emission rate derived from CEMS data.
[2] Potential NOx emissions estimated based on the Phase II NOx Averaging Plan alternative contemporaneous emission limitation for Unit SG03.
[3] H_2SO_4 emissions (representing inorganic condensables) calculated based on the EPRI report *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants*, Technical Update (March 2008).
[4] Condensable organics emissions estimated based on the report *Estimated Emissions of Condensable Carbon and Condensable SO_3 From Coal-Fired Power Plants* (Edgerton, June 2006). See Appendix B of the BART modeling protocols submitted by Georgia Power in July 2006 for more details.
[5] Filterable PM10 and PM2.5 determined by applying AP-42 PM10 and PM2.5 fractions for coal-fired boilers to the total filterable PM estimate.

IN THE MATTER OF THE DRAFT TITLE V PERMIT FOR RRI ENERGY MID ATLANTIC POWER HOLDINGS LLC SHAWVILLE GENERATING STATION DRAFT TITLE V/STATE OPERATING PERMIT IN CLEARFIELD COUNTY, PA ISSUED BY THE PENNSYLVANIA DEPARTMENT OF ENVIRONMENTAL PROTECTION	))))))))))	ID NO. 17-00001

DECLARATION OF

RANAJIT (RON) SAHU

(1) I, Ranajit Sahu, am an environmental engineer with more than 18 years of experience in program and project management services; design and specification of pollution control equipment; soils and groundwater remediation; combustion engineering evaluations; energy studies; and multimedia environmental regulatory compliance and permitting, among other things. In addition to my consulting work for private industry on New Source Review and other matters, I have testified on behalf of the United States in several New Source Review enforcement actions in federal court.

(2) I have a B.S., M.S., and Ph.D. in Mechanical Engineering, the first from the Indian Institute of Technology (Kharagpur, India) and the latter two from the California Institute

EXHIBIT F

of Technology (Caltech) in Pasadena, California. My research specialization was in the combustion of coal and, among other things, understanding air pollution aspects of coal combustion in power plants.

(3) A copy of my current resume is provided in Attachment A.

(4) It is my understanding that the current matter pertains to the emissions of a class of air pollutants known as particulate matter from the coal-fired boilers at the Shawville Generating Station (SGS), owned by RRI Energy Mid-Atlantic Power Holdings LLC. SGS consists of four boilers, numbered Units 1 through 4. Units 1 and 2 (1954) are dry bottom, front wall-fired balanced draft sub-critical boilers fired using bituminous coal and No. 2 oil. Units 3 (1959) and 4 (1960) are tangential fired boilers firing the same fuels.

(5) Among other pollutants, coal-fired power plant boilers such as the Shawville Units 1 through 4, can emit particulate matter (PM) or dust of varying size and chemical composition. Total suspended particulate (TSP) matter will be referred to simply as PM. Particles with an aerodynamic diameter[1] of 10 micrometers (or microns) or smaller will be denoted as PM10. Particles with aerodynamic diameters 2.5 micrometers or smaller

[1] In air pollution control, it is necessary to use a particle size definition that directly relates to how the particle behaves in a fluid such as air. The term "aerodynamic diameter" has been developed by aerosol physicists in order to provide a simple means of categorizing the sizes of particles having different shapes and densities with a single dimension. The **aerodynamic diameter** is the diameter of a spherical particle having a density of 1 gm/cm^3 that has the same inertial properties [i.e. terminal settling velocity] in the gas as the particle of interest. See http://www.epa.gov/apti/bces/module3/diameter/diameter.htm.

will be denoted as PM2.5. By comparison, the diameter of typical human hair is around 70 to 100 micrometers.

(6) Particles collected, in any of the size classes above, are also classified into two fractions – namely the filterable and the condensable portions. Filterable particles are those that are present in a form suitably collected by a filter present in the exhaust gas path. Condensable particles are those that may be present in the vapor phase at the exhaust gas temperature but which can condense into particles at the lower temperatures present in the ambient air. Together the filterable and condensable fractions are sometimes referred to as the "total" in any size class. Finally, these total (filterable plus condensable) fractions are sometimes referred to as the primary particulates since they are directly emitted by the source boiler. Other particles that can form in the atmosphere resulting from gaseous emissions from the boiler are sometimes referred to as secondary particles.

(7) Primary particles are emitted because the combustion of coal in a boiler results in the formation of flyash, which, in turn, is due to the presence of mineral matter in coal that cannot be burned (unlike the carbon which does burn in the boiler). Some of the mineral matter transforms to bottom ash, which is not entrained in the combustion exhaust air and drops down to the bottom in the boiler. But, typically, a significant fraction (greater than 50%) of the ash is emitted from the boiler as fly ash.

(8) I have been asked to provide an opinion, in general, on how emissions of primary, filterable PM, PM10, and PM2.5 can vary from a coal-fired power plant boiler, such as any of the Shawville units, equipped with electrostatic precipitators (ESP).

(9) SGS Units 1 and 2 are each equipped with 2 ESPs, while SGS Units 3 and 4 are each equipped with 4 ESPs. All of the ESP units are "cold" side units meaning that they are located after the respective combustion air preheaters.

(10) Without any air pollution controls, the bulk of the fly ash containing filterable PM/PM10/PM2.5 would simply be emitted to the atmosphere from the boiler. However, almost all boilers use particulate control devices to prevent or minimize that. The vast majority of these are either fabric filters (typically the newer boilers) or ESPs.

(11) The basic principle of operation of ESPs is as follows. A high voltage corona discharge is used to electrically charge the flyash particles. The charged particles then migrate in an applied electric field to the collection electrode where they accumulate. For example, negatively charged particles migrate to the positive electrode. The collected particles are subsequently removed by mechanical action (or rapping) where they fall into collection hoppers for disposal.

(12) There are two major charging processes, field charging and diffusion charging. Field charging refers to the bombardment of the particles by negative ions, moving under the influence of the electric field. The charge acquired depends on the charging field, the surface area and dielectric properties of the particle, and the time available for charging. This is the most important means of charging particles greater than 1 micrometer in aerodynamic diameter. Diffusion charging results from the thermal or random motion of ions causing them to diffuse through the surrounding gas. As particles collide with the diffusing ions, charge is transferred. The charge attained in this case depends on particle size, gas characteristics, gas temperature, and the time available for charging. Diffusion

charging is most significant for particles smaller than 0.1 micrometers in aerodynamic diameter. Since both processes occur simultaneously, there is a relative minimum in combined efficiency for both processes for particle diameters around 1 micrometer in aerodynamic diameter.

(13) The overall efficacy of an ESPs is expressed in terms of its "efficiency" which is defined as the ratio of the mass of particles removed by the ESP to the mass of particles entering the ESP.

(14) The emissions of PM/PM10/PM2,5 can vary from coal-fired boilers because they depend on numerous factors. While a complete and exhaustive listing of every single factor that can affect emissions of these pollutants would be almost impossible to compile, based on my experience the following factors should be considered. I have grouped them into properties of the fuel (coal), properties of the flyash particles themselves, and factors affecting ESP performance.

(15) Collectively, all of these factors, their interactions, and their variation with time, will affect how much primary, filterable PM/PM10/PM2,5 is actually emitted. In addition, there are numerous additional factors that affect the accuracy and variability of how much PM/PM10/PM2.5 are measured. Thus, the observed variability of these emissions is a combination of the factors listed below and the factors associated with the measurement process.

(16) The more important properties of the coal that can effect PM/PM10/PM2.5 emissions are:

• Mineral matter or ash quantity. Lower the mineral matter content, less particulate emissions are produced. In addition, reduction in ash loading tends to improve ESP efficiency.

• Fly-ash electrical resistivity. Since the collection of the particles at the later ESP depends on the ability of the particles to be electrically charged, their electrical resistivity plays an important role. If the resistivity is too low, particles can lose their charge either before collection or they may be released back into the exhaust gas stream after collection. If the resistivity is too high, the collected particles cannot easily be dislodged from the ESP collecting electrode and this reduces ESP efficiency.

• Coal moisture content. Coal moisture content can affect the exhaust gas flow rate and temperature, both of which will affect collection efficiency.

• Ash chemical composition. The particle electrical resistivity as well as the ability of various exhaust gas components to condense (on other ash particles), depends on the chemical composition of the coal and the mineral matter.

• Ash particle size. Migration velocity and therefore particle collection rates decrease in proportion to the size of the particle (Darby 1983; Wibberley and Wall 1985).

(17) Properties of the particles themselves that can effect PM/PM10/PM2.5 emissions are as follows:

• Electrical characteristics. Particle electrical characteristics are determined by the resistivity of the fly-ash after it has formed an ash layer on the collecting surface. If the resistance level is high, the corona current passing through the ash layer must be generally reduced or back corona effects will reduce the performance of the ESP. The range of resistivity is affected by the chemistry of the ash, moisture in the flue gas, levels of other chemicals such as sulfur trioxide and flue gas temperature.

• Size distribution. Dust collection is affected by the particle size due to the two mechanisms of particle charging described earlier.

• Migration velocity. The speed of the movement of charged particles to the collection electrodes is denoted by the electrostatic migration velocity which, in turn, depends on a number of assumptions concerning the flow and nature of the charging mechanism. The effective migration velocity is an indication of a precipitator's ability to collect a specific sample of PM/PM10/PM2.5 at a specific operating condition. The effective migration velocity varies with particle size.

• Particle shape. Particle shape can influence collection efficiency because shape affects the ability of the particle to be charged as well as the migration properties of the particles. Angular particles tend to interlock in the collected layer on the ESP plates and be rapped/removed in a more coherent agglomerate, resulting in less re-entrainment than spherical particles.

• Particle cohesivity. Particle cohesivity (the ability to adhere to one another) on the plates of an ESP is also an important factor in relation to re-entrainment. The more cohesive the particles, the less likely they will be re-entrained into the gas stream.

• Unburnt carbon content. The unburnt carbon content for a particle is a reflection of the coal reactivity as well as the combustion conditions. High levels of unburnt carbon (which depend on combustion conditions) can affect particle resistivity.

(18) In addition to the above, important factors that affect the overall collection efficiency of an ESP include:

• Particle residence time. The time available to charge and collect a dust particle. In turn, this depends on particle shape and size. It also depends on specific geometrical aspects such as the position of the particle in relation to the electrical field at the entry to the ESP.

• Gas flow and particle concentration uniformity. If the exhaust gas flow entering the ESP is not uniform, it will adversely affect the residence time and therefore the efficiency.

• ESP Power. The overall electrical energy available to charge the ash.

• Electrode cleaning. The effectiveness of dust removal from electrodes within the ESP.

• Sneakage. This refers to ash bypassing the electrical sections of the ESP, i.e. between discharge and collection electrodes, and thus escaping capture.

• Back corona. This occurs when the ash layer on the collector surface has reached a level of resistivity that the accumulated layer breaks down and produces a flow of positive ions back towards the negative high voltage discharge electrode.

• Re-entrainment of particles. This refers to the reintroduction of particles to the gas stream from the discharge electrodes and collecting surfaces during rapping. It can also result from gas sweepage, when gas that bypasses the treatment zone of the ESP, disturbs collection zones such as hoppers.

(19) Of course, in addition to the factors listed above, the overall age, condition, deterioration, maintenance and other factors of the boilers and the ESPs will also affect the emissions of these pollutants.

(20) Given these numerous factors discussed above that can, singly and in combination, affect the emissions of these pollutants from each of the Shawville boilers, the emissions of PM/PM10/PM2.5 will likely be variable, and significantly so. For example, in my experience, it is not uncommon for such variability to be multiple-times or even an order or magnitude different between the typical three back-to-back hourly test runs in a stack test. Thus, it is highly unlikely that an occasional measurement (such as a stack test) will accurately be able to capture such variability. A stack test is a snap-shot in time and cannot possible provide any information for the periods between tests. Thus, continuous measurements of filterable PM, using CEMS that

are now available, are the proper means of accurately measuring such emissions. Such continuous measurements, done properly, will capture the variability of these emissions over time and therefore provide a more accurate record of the emissions from the Shawville units.

I declare under penalty of perjury that the foregoing is true and correct.

Ranajit Sahu

Executed on February 14, 2011 in Alhambra, CA

RANAJIT (RON) SAHU, Ph.D, QEP, CEM (Nevada)

CONSULTANT, ENVIRONMENTAL AND ENERGY ISSUES

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EXPERIENCE SUMMARY

Dr. Sahu has over twenty one years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services; design and specification of pollution control equipment; soils and groundwater remediation; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

He has over nineteen years of project management experience and has successfully managed and executed numerous projects in this time period. This includes basic and applied research projects, design projects, regulatory compliance projects, permitting projects, energy studies, risk assessment projects, and projects involving the communication of environmental data and information to the public. Notably, he has successfully managed a complex soils and groundwater remediation project with a value of over $140 million involving soils characterization, development and implementation of the remediation strategy, regulatory and public interactions and other challenges.

He has provided consulting services to numerous private sector, public sector and public interest group clients. His major clients over the past seventeen years include various steel mills, petroleum refineries, cement companies, aerospace companies, power generation facilities, lawn and garden equipment manufacturers, spa manufacturers, chemical distribution facilities, and various entities in the public sector including EPA, the US Dept. of Justice, California DTSC, various municipalities, etc.). Dr. Sahu has performed projects in over 44 states, numerous local jurisdictions and internationally.

Dr. Sahu's experience includes various projects in relation to industrial waste water as well as storm water pollution compliance include obtaining appropriate permits (such as point source NPDES permits) as well development of plans, assessment of remediation technologies, development of monitoring reports, and regulatory interactions.

In addition to consulting, Dr. Sahu has taught and continues to teach numerous courses in several Southern California universities including UCLA (air pollution), UC Riverside (air pollution, process hazard analysis), and Loyola Marymount University (air pollution, risk assessment, hazardous waste management) for the past seventeen years. In this time period he has also taught at Caltech, his alma mater and at USC (air pollution) and Cal State Fullerton (transportation and air quality).

Dr. Sahu has and continues to provide expert witness services in a number of environmental areas discussed above in both state and Federal courts as well as before administrative bodies (please see Annex A).

EXPERIENCE RECORD

2000-present **Independent Consultant.** Providing a variety of private sector (industrial companies, land development companies, law firms, etc.) public sector (such as the US Department of Justice) and public interest group clients with project management, air quality consulting, waste remediation and management consulting, as well as regulatory and engineering support consulting services.

1995-2000 Parsons ES, **Associate, Senior Project Manager and Department Manager for** Air Quality/Geosciences/Hazardous Waste Groups, Pasadena. Responsible for the management of a group of approximately 24 air quality and environmental professionals, 15 geoscience, and 10 hazardous waste professionals providing full-service consulting, project management, regulatory compliance and A/E design assistance in all areas.

Parsons ES, **Manager for Air Source Testing Services**. Responsible for the management of 8 individuals in the area of air source testing and air regulatory permitting projects located in Bakersfield, California.

1992-1995 Engineering-Science, Inc. **Principal Engineer and Senior Project Manager** in the air quality department. Responsibilities included multimedia regulatory compliance and permitting (including hazardous and nuclear materials), air pollution engineering (emissions from stationary and mobile sources, control of criteria and air toxics, dispersion modeling, risk assessment, visibility analysis, odor analysis), supervisory functions and project management.

1990-1992 Engineering-Science, Inc. **Principal Engineer and Project Manager** in the air quality department. Responsibilities included permitting, tracking regulatory issues, technical analysis, and supervisory functions on numerous air, water, and hazardous waste projects. Responsibilities also include client and agency interfacing, project cost and schedule control, and reporting to internal and external upper management regarding project status.

1989-1990 Kinetics Technology International, Corp. **Development Engineer.** Involved in thermal engineering R&D and project work related to low-NOx ceramic radiant burners, fired heater NOx reduction, SCR design, and fired heater retrofitting.

1988-1989 Heat Transfer Research, Inc. **Research Engineer**. Involved in the design of fired heaters, heat exchangers, air coolers, and other non-fired equipment. Also did research in the area of heat exchanger tube vibrations.

EDUCATION

1984-1988 Ph.D., Mechanical Engineering, California Institute of Technology (Caltech), Pasadena, CA.

1984 M. S., Mechanical Engineering, Caltech, Pasadena, CA.

1978-1983 B. Tech (Honors), Mechanical Engineering, Indian Institute of Technology (IIT) Kharagpur, India

TEACHING EXPERIENCE

Caltech

"Thermodynamics," Teaching Assistant, California Institute of Technology, 1983, 1987.

"Air Pollution Control," Teaching Assistant, California Institute of Technology, 1985.

"Caltech Secondary and High School Saturday Program," - taught various mathematics (algebra through calculus) and science (physics and chemistry) courses to high school students, 1983-1989.

"Heat Transfer," - taught this course in the Fall and Winter terms of 1994-1995 in the Division of Engineering and Applied Science.

"Thermodynamics and Heat Transfer," Fall and Winter Terms of 1996-1997.

U.C. Riverside, Extension

"Toxic and Hazardous Air Contaminants," University of California Extension Program, Riverside, California. Various years since 1992.

"Prevention and Management of Accidental Air Emissions," University of California Extension Program, Riverside, California. Various years since 1992.

"Air Pollution Control Systems and Strategies," University of California Extension Program, Riverside, California, Summer 1992-93, Summer 1993-1994.

"Air Pollution Calculations," University of California Extension Program, Riverside, California, Fall 1993-94, Winter 1993-94, Fall 1994-95.

"Process Safety Management," University of California Extension Program, Riverside, California. Various years since 1992-2010.

"Process Safety Management," University of California Extension Program, Riverside, California, at SCAQMD, Spring 1993-94.

"Advanced Hazard Analysis - A Special Course for LEPCs," University of California Extension Program, Riverside, California, taught at San Diego, California, Spring 1993-1994.

"Advanced Hazardous Waste Management" University of California Extension Program, Riverside, California. 2005.

Loyola Marymount University

"Fundamentals of Air Pollution - Regulations, Controls and Engineering," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1993.

"Air Pollution Control," Loyola Marymount University, Dept. of Civil Engineering, Fall 1994.

"Environmental Risk Assessment," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1998.

"Hazardous Waste Remediation" Loyola Marymount University, Dept. of Civil Engineering. Various years since 2006.

University of Southern California

"Air Pollution Controls," University of Southern California, Dept. of Civil Engineering, Fall 1993, Fall 1994.

"Air Pollution Fundamentals," University of Southern California, Dept. of Civil Engineering, Winter 1994.

University of California, Los Angeles

"Air Pollution Fundamentals," University of California, Los Angeles, Dept. of Civil and Environmental Engineering, Spring 1994, Spring 1999, Spring 2000, Spring 2003, Spring 2006, Spring 2007, Spring 2008, Spring 2009.

International Programs

"Environmental Planning and Management," 5 week program for visiting Chinese delegation, 1994.

"Environmental Planning and Management," 1 day program for visiting Russian delegation, 1995.

"Air Pollution Planning and Management," IEP, UCR, Spring 1996.

"Environmental Issues and Air Pollution," IEP, UCR, October 1996.

PROFESSIONAL AFFILIATIONS AND HONORS

President of India Gold Medal, IIT Kharagpur, India, 1983.

Member of the Alternatives Assessment Committee of the Grand Canyon Visibility Transport Commission, established by the Clean Air Act Amendments of 1990, 1992-present.

American Society of Mechanical Engineers: Los Angeles Section Executive Committee, Heat Transfer Division, and Fuels and Combustion Technology Division, 1987-present.

Air and Waste Management Association, West Coast Section, 1989-present.

PROFESSIONAL CERTIFICATIONS

EIT, California (# XE088305), 1993.

REA I, California (#07438), 2000.

Certified Permitting Professional, South Coast AQMD (#C8320), since 1993.

QEP, Institute of Professional Environmental Practice, since 2000.

CEM, State of Nevada (#EM-1699). Expiration 10/07/2011.

PUBLICATIONS (PARTIAL LIST)

"Physical Properties and Oxidation Rates of Chars from Bituminous Coals," with Y.A. Levendis, R.C. Flagan and G.R. Gavalas, *Fuel*, **67**, 275-283 (1988).

"Char Combustion: Measurement and Analysis of Particle Temperature Histories," with R.C. Flagan, G.R. Gavalas and P.S. Northrop, *Comb. Sci. Tech.* **60**, 215-230 (1988).

"On the Combustion of Bituminous Coal Chars," PhD Thesis, California Institute of Technology (1988).

"Optical Pyrometry: A Powerful Tool for Coal Combustion Diagnostics," *J. Coal Quality*, **8**, 17-22 (1989).

"Post-Ignition Transients in the Combustion of Single Char Particles," with Y.A. Levendis, R.C.Flagan and G.R. Gavalas, *Fuel*, **68**, 849-855 (1989).

"A Model for Single Particle Combustion of Bituminous Coal Char." Proc. ASME National Heat Transfer Conference, Philadelphia, **HTD-Vol. 106**, 505-513 (1989).

"Discrete Simulation of Cenospheric Coal-Char Combustion," with R.C. Flagan and G.R.Gavalas, *Combust. Flame*, **77**, 337-346 (1989).

"Particle Measurements in Coal Combustion," with R.C. Flagan, in "**Combustion Measurements**" (ed. N. Chigier), Hemisphere Publishing Corp. (1991).

"Cross Linking in Pore Structures and Its Effect on Reactivity," with G.R. Gavalas in preparation.

"Natural Frequencies and Mode Shapes of Straight Tubes," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Optimal Tube Layouts for Kamui SL-Series Exchangers," with K. Ishihara, Proprietary Report for Kamui Company Limited, Tokyo, Japan (1990).

"HTRI Process Heater Conceptual Design," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Asymptotic Theory of Transonic Wind Tunnel Wall Interference," with N.D. Malmuth and others, Arnold Engineering Development Center, Air Force Systems Command, USAF (1990).

"Gas Radiation in a Fired Heater Convection Section," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1990).

"Heat Transfer and Pressure Drop in NTIW Heat Exchangers," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1991).

"NOx Control and Thermal Design," Thermal Engineering Tech Briefs, (1994).

"From Puchase of Landmark Environmental Insurance to Remediation: Case Study in Henderson, Nevada," with Robin E. Bain and Jill Quillin, presented at the AQMA Annual Meeting, Florida, 2001.

"The Jones Act Contribution to Global Warming, Acid Rain and Toxic Air Contaminants," with Charles W. Botsford, presented at the AQMA Annual Meeting, Florida, 2001.

PRESENTATIONS (PARTIAL LIST)

"Pore Structure and Combustion Kinetics - Interpretation of Single Particle Temperature-Time Histories," with P.S. Northrop, R.C. Flagan and G.R. Gavalas, presented at the AIChE Annual Meeting, New York (1987).

"Measurement of Temperature-Time Histories of Burning Single Coal Char Particles," with R.C. Flagan, presented at the American Flame Research Committee Fall International Symposium, Pittsburgh, (1988).

"Physical Characterization of a Cenospheric Coal Char Burned at High Temperatures," with R.C. Flagan and G.R. Gavalas, presented at the Fall Meeting of the Western States Section of the Combustion Institute, Laguna Beach, California (1988).

"Control of Nitrogen Oxide Emissions in Gas Fired Heaters - The Retrofit Experience," with G. P. Croce and R. Patel, presented at the International Conference on Environmental Control of Combustion Processes (Jointly sponsored by the American Flame Research Committee and the Japan Flame Research Committee), Honolulu, Hawaii (1991).

"Air Toxics - Past, Present and the Future," presented at the Joint AIChE/AAEE Breakfast Meeting at the AIChE 1991 Annual Meeting, Los Angeles, California, November 17-22 (1991).

"Air Toxics Emissions and Risk Impacts from Automobiles Using Reformulated Gasolines," presented at the Third Annual Current Issues in Air Toxics Conference, Sacramento, California, November 9-10 (1992).

"Air Toxics from Mobile Sources," presented at the Environmental Health Sciences (ESE) Seminar Series, UCLA, Los Angeles, California, November 12, (1992).

"Kilns, Ovens, and Dryers - Present and Future," presented at the Gas Company Air Quality Permit Assistance Seminar, Industry Hills Sheraton, California, November 20, (1992).

"The Design and Implementation of Vehicle Scrapping Programs," presented at the 86th Annual Meeting of the Air and Waste Management Association, Denver, Colorado, June 12, 1993.

"Air Quality Planning and Control in Beijing, China," presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, Ohio, June 19-24, 1994.

Annex A

Expert Litigation Support

1. Matters for which Dr. Sahu has have provided depositions and affidavits/expert reports include:

(a) Deposition on behalf of Rocky Mountain Steel Mills, Inc. located in Pueblo, Colorado – dealing with the manufacture of steel in mini-mills including methods of air pollution control and BACT in steel mini-mills and opacity issues at this steel mini-mill

(b) Affidavit for Rocky Mountain Steel Mills, Inc. located in Pueblo Colorado – dealing with the technical uncertainties associated with night-time opacity measurements in general and at this steel mini-mill.

(c) Expert reports and depositions (2/28/2002 and 3/1/2002; 12/2/2003 and 12/3/2003; 5/24/2004) on behalf of the US Department of Justice in connection with the Ohio Edison NSR Cases. *United States, et al. v. Ohio Edison Co., et al.*, C2-99-1181 (S.D. Ohio).

(d) Expert reports and depositions (5/23/2002 and 5/24/2002) on behalf of the US Department of Justice in connection with the Illinois Power NSR Case. *United States v. Illinois Power Co., et al.*, 99-833-MJR (S.D. Ill.).

(e) Expert reports and depositions (11/25/2002 and 11/26/2002) on behalf of the US Department of Justice in connection with the Duke Power NSR Case. *United States, et al. v. Duke Energy Corp.*, 1:00-CV-1262 (M.D.N.C.).

(f) Expert reports and depositions (10/6/2004 and 10/7/2004; 7/10/2006) on behalf of the US Department of Justice in connection with the American Electric Power NSR Cases. *United States, et al. v. American Electric Power Service Corp., et al.*, C2-99-1182, C2-99-1250 (S.D. Ohio).

(g) Affidavit (March 2005) on behalf of the Minnesota Center for Environmental Advocacy and others in the matter of the Application of Heron Lake BioEnergy LLC to construct and operate an ethanol production facility – submitted to the Minnesota Pollution Control Agency.

(h) Expert reports and depositions (10/31/2005 and 11/1/2005) on behalf of the US Department of Justice in connection with the East Kentucky Power Cooperative NSR Case. *United States v. East Kentucky Power Cooperative, Inc.*, 5:04-cv-00034-KSF (E.D. KY).

(i) Deposition (10/20/2005) on behalf of the US Department of Justice in connection with the Cinergy NSR Case. *United States, et* al. *v. Cinergy Corp., et al.*, IP 99-1693-C-M/S (S.D. Ind.).

(j) Affidavits and deposition on behalf of Basic Management Inc. (BMI) Companies in connection with the BMI vs. USA remediation cost recovery Case.

(k) Expert report on behalf of Penn Future and others in the Cambria Coke plant permit challenge in Pennsylvania.

(l) Expert report on behalf of the Appalachian Center for the Economy and the Environment and others in the Western Greenbrier permit challenge in West Virginia.

(m) Expert report, deposition (via telephone on January 26, 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) in the Thompson River Cogeneration LLC Permit No. 3175-04 challenge.

(n) Expert report and deposition (2/2/07) on behalf of the Texas Clean Air Cities Coalition at the Texas State Office of Administrative Hearings (SOAH) in the matter of the permit challenges to TXU Project Apollo's eight new proposed PRB-fired PC boilers located at seven TX sites.

(o) Expert testimony (July 2007) on behalf of the Izaak Walton League of America and others in connection with the acquisition of power by Xcel Energy from the proposed Gascoyne Power Plant – at the State of Minnesota, Office of Administrative Hearings for the Minnesota PUC (MPUC No. E002/CN-06-1518; OAH No. 12-2500-17857-2).

(p) Affidavit (July 2007) Comments on the Big Cajun I Draft Permit on behalf of the Sierra Club – submitted to the Louisiana DEQ.

(q) Expert reports and deposition (12/13/2007) on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (W.D. Pennsylvania).

(r) Expert reports and pre-filed testimony before the Utah Air Quality Board on behalf of Sierra Club in the Sevier Power Plant permit challenge.

(s) Expert reports and deposition (October 2007) on behalf of MTD Products Inc., in connection with General Power Products, LLC v MTD Products Inc., 1:06 CVA 0143 (S.D. Ohio, Western Division)

(t) Experts report and deposition (June 2008) on behalf of Sierra Club and others in the matter of permit challenges (Title V: 28.0801-29 and PSD: 28.0803-PSD) for the Big Stone II unit, proposed to be located near Milbank, South Dakota.

(u) Expert reports, affidavit, and deposition (August 15, 2008) on behalf of Earthjustice in the matter of air permit challenge (CT-4631) for the Basin Electric Dry Fork station, under construction near Gillette, Wyoming before the Environmental Quality Council of the State of Wyoming.

(v) Affidavit/Declaration and Expert Report on behalf of NRDC and the Southern Environmental Law Center in the matter of the air permit challenge for Duke Cliffside Unit 6, under construction in North Carolina.

(w) Dominion Wise County MACT Declaration (August 2008)

(x) Expert Report on behalf of Sierra Club for the Green Energy Resource Recovery Project, MACT Analysis (June 13, 2008).

(y) Expert Report on behalf of Sierra Club and the Environmental Integrity Project in the matter of the air permit challenge for NRG Limestone's proposed Unit 3 in Texas (February 2009).

(z) Expert Report and deposition on behalf of MTD Products, Inc., in the matter of Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al. (June 2009, July 2009).

(aa) Expert Report on behalf of Sierra Club and the Southern Environmental Law Center in the matter of the air permit challenge for Santee Cooper's proposed Pee Dee plant in South Carolina (August 2009).

(bb) Statements (May 2008 and September 2009) on behalf of the Minnesota Center for Environmental Advocacy to the Minnesota Pollution Control Agency in the matter of the Minnesota Haze State Implementation Plans.

(cc) Expert Report (August 2009) and Deposition (October 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(dd) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Coleto Creek coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH). (October 2009).

(ee) Expert Report, Rebuttal Report (September 2009) and Deposition (October 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.

(ff) Expert report (December 2009), Rebuttal reports (May 2010 and June 2010) and depositions (June 2010) on behalf of the US Department of Justice in connection with the Alabama Power Company NSR Case. *United States v. Alabama Power Company*, CV-01-HS-152-S (Northern District of Alabama, Southern Division).

(gg) Prefiled testimony (October 2009) and Deposition (December 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(hh) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Tenaska coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH). (April 2010).

(ii) Written Direct Testimony (July 2010) and Written Rebuttal Testimony (August 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions,* No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

(jj) Expert report (August 2010) and Rebuttal Expert Report (October 2010) on behalf of the US Department of Justice in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

(kk) Declaration (August 2010) on behalf of the US EPA and US Department of Justice in the matter of DTE Energy Company, Detroit, MI (Monroe Unit 2).

(ll) Expert Report and Deposition (August 2010) as well as Affidavit (September 2010) on behalf of Kentucky Waterways Alliance, Sierra Club, and Valley Watch in the matter of challenges to the NPDES permit issued for the Trimble County power plant by the Kentucky Energy and Environment Cabinet to Louisville Gas and Electric, File No. DOW-41106-047.

(mm) Expert Report (August 2010) and Rebuttal Expert Report (September 2010) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (D. Colo.).

(nn) Written Direct Expert Testimony (August 2010) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

(oo) Deposition (August 2010) on behalf of Environmental Defense, in the matter of the remanded permit challenge to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(pp) Expert Report, Supplemental/Rebuttal Expert Report, and Declarations (October 2010) on behalf of New Mexico Environment Department (Plaintiff-Intervenor), Grand Canyon Trust and Sierra Club (Plaintiffs) in the matter of Public Service Company of New Mexico (PNM)'s Mercury Report for the San Juan Generating Station, CIVIL NO. 1:02-CV-0552 BB/ATC (ACE). US District Court for the District of New Mexico.

(qq) Comment Report (October 2010) on the Draft Permit Issued by the Kansas DHE to Sunflower Electric for Holcomb Unit 2. Prepared on behalf of the Sierra Club and Earthjustice.

(rr) Expert Report (October 2010) and Rebuttal Expert Report (November 2010) (BART Determinations for PSCo Hayden and CSU Martin Drake units) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

(ss) Expert Report (November 2010) (BART Determinations for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

(tt) Comment Report (December 2010) on the Pennsylvania Department of Environmental Protection (PADEP)'s Proposal to grant Plan Approval for the Wellington Green Energy Resource Recovery Facility on behalf of the Chesapeake Bay Foundation, Group Against Smog and Pollution (GASP), National Park Conservation Association (NPCA), and the Sierra Club.

(uu) Written Expert Testimony (January 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

2. Occasions where Dr. Sahu has provided oral testimony <u>at trial or in similar proceedings</u> include the following:

(vv) In February, 2002, provided expert witness testimony on emissions data on behalf of Rocky Mountain Steel Mills, Inc. in Denver District Court.

(ww) In February 2003, provided expert witness testimony on regulatory framework and emissions calculation methodology issues on behalf of the US Department of Justice in the Ohio Edison NSR Case in the US District Court for the Southern District of Ohio.

(xx) In June 2003, provided expert witness testimony on regulatory framework, emissions calculation methodology, and emissions calculations on behalf of the US Department of Justice in the Illinois Power NSR Case in the US District Court for the Southern District of Illinois.

(yy) In August 2006, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Western Greenbrier) on behalf of the Appalachian Center for the Economy and the Environment in West Virginia.

(zz) In May 2007, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Thompson River Cogeneration) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) before the Montana Board of Environmental Review.

(aaa) In October 2007, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Sevier Power Plant) on behalf of the Sierra Club before the Utah Air Quality Board.

(bbb) In August 2008, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Big Stone Unit II) on behalf of the Sierra Club and Clean Water before the South Dakota Board of Minerals and the Environment.

(ccc) In February 2009, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Santee Cooper Pee Dee units) on behalf of the Sierra Club and the Southern Environmental Law Center before the South Carolina Board of Health and Environmental Control.

(ddd) In February 2009, provided expert witness testimony regarding power plant emissions, BACT issues and MACT issues on a permit challenge (NRG Limestone Unit 3) on behalf of the Sierra Club and the Environmental Integrity Project before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(eee) In November 2009, provided expert witness testimony regarding power plant emissions, BACT issues and MACT issues on a permit challenge (Las Brisas Energy Center) on behalf of the Environmental Defense Fund before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(fff) In February 2010, provided expert witness testimony regarding power plant emissions, BACT issues and MACT issues on a permit challenge (White Stallion Energy Center) on behalf of the Environmental Defense Fund before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(ggg) In September 2010 provided oral trial testimony on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, State of Maryland, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case in US District Court in the Western District of Pennsylvania. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (W.D. Pennsylvania).

(hhh) Oral Direct and Rebuttal Expert Testimony (September 2010) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

(iii) Oral Testimony (September 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions,* No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

(jjj) Oral Testimony (October 2010) regarding mercury and total PM/PM10 emissions and other issues on a remanded permit challenge (Las Brisas Energy Center) on behalf of the Environmental Defense Fund before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(kkk) Oral Testimony (November 2010) regarding BART for PSCo Hayden, CSU Martin Drake units before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

(lll) Oral Testimony (December 2010) regarding BART for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

(mmm) Deposition (December 2010) on behalf of the US Department of Justice in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

(nnn) Deposition (February 2011) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (D. Colo.).

(ooo) Oral Expert Testimony (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).