Transport Rule
Key Points
June 21, 2011

- Allowance allocations should reflect actual emissions and should not be based strictly on heat input. Under EPA's proposed allowance allocation methodology in the third Notice of Data Availability (i.e., NODA 3), natural gas units would receive a windfall of allowances. Utilities have no compliance options other than to purchase emission allowances. Therefore, allowance allocations ***must*** be based on need.

- The proposed compliance deadlines of 2012 and 2014 are unreasonable, unnecessary, and disruptive to compliance planning. The necessary emission controls cannot be built by 2012 or 2014. EPA has greatly underestimated the amount of time required to design, permit, construct, and start up new FGDs and SCRs. Compliance should not begin any sooner than 2015.

- The proposed Transport Rule suffered from numerous errors in methodologies and numerous incorrect data and assumptions which impacted every aspect of the proposed Transport Rule. EPA continuously changed some aspects of the proposed rule without giving stakeholders an opportunity to comment on the entire package. EPA should correct all the errors, re-propose the rule, and allow an adequate opportunity to comment.

Allocations should reflect actual emissions and should not be based strictly on heat input. The compliance dates in the proposed rule do not give sources any options for compliance other than purchasing emission allowances. With compliance options so limited, it is imperative that allocations are be based on need.

EPA's pure heat-input based allocation method (i.e., NODA3 Option 1) is arbitrary and leads to absurd results. For example, in this approach, many large natural gas fired units would receive allocations more than 500 times their highest single year of emissions during the seven-year baseline period that EPA evaluates in NODA3. This option provides an overwhelming windfall to natural gas-fired units, and results in significant under–allocation to coal-based generation, with no consideration of allowance needs. Table 1 (and Attachment 1) below illustrates this imbalance for SO2. EPA should not develop a pure heat-input based allocation scheme that does not give any consideration to historical emissions or need.

Table 1. Example of SO2 Allowances Allocations at Various Southern Company Units

	Unit Type	Name Plate Capacity (MW)	Max 2003-2009 Emissions (tons)	Proposed Transport Rule	NODA3 Option 1	NODA3 Option 2
McIntosh CC Unit 10	Combined Cycle	659	8	8	4,715	884
Barry CC Unit 6	Combined Cycle	535	6	7	2,741	783
Bowen Unit 1	Steam Boiler	700	44,181	2,742	10,734	11,695
Crist Unit 4	Steam Boiler	75	3,757	2,752	510	742
Branch Unit 4	Steam Boiler	490	32,828	25,162	6,692	7,291
Miller Unit 4	Steam Boiler	660	15,029	1,607	8,079	9,248

If EPA uses a heat-input based allocation method, it must use an emission constraint that grounds a unit's allocations in reality – using real and credible emissions data. In NODA3 Option 2, EPA attempts to correct the inconceivable over-allocations that result from a straight heat-input based method (i.e., Option 1). To do so, EPA essentially caps a unit's allocation at the greater of its "maximum historical baseline emissions" (i.e., highest emissions for each compliance period from 2003 to 2009) and its "well-controlled-rate-maximum" (a calculated value). Option 2 contains hundreds and hundreds of examples of gross under- and over-allocations after applying Option 2's emission constraint. Put simply, EPA's emission constraint failed. The bulk of that failure is due to the flawed "well-controlled-rate-maximum" value.

For a unit that reports hourly heat input, the "well-controlled-rate maximum" equals:

- that unit's maximum hourly heat input,
- multiplied by 0.06 lbs/mmBtu (for both SO2 and NOx allocations),
- multiplied by 8,760 hours (or 3,672 for ozone season),
- multiplied by set-technology-specific capacity factors.

This approach is fundamentally flawed. Option 2 can still lead to allocations that are 200 times greater than a unit's "maximum historical baseline emissions" (see Table 1 above and EPA's NODA3 Allocation Tables in the Docket). Also, there is no basis to use an emission rate (0.06 lbs/mmBtu for both SO2 and NOx) that is admittedly based on a well-controlled *coal* unit for all units. Individual units have significantly different emission rates depending on the fuel used; there is no reason for EPA to ignore such a fact when calculating an emissions value. Further, EPA's use of technology-specific capacity factors does not remedy the flaw. EPA's capacity factors are based on its effort to determine a realistic average capacity for certain technology types. Doing so might lead to a defensible prediction of maximum emissions if a proper fuel- or technology-specific emission rate were used, but given EPA's use of a coal-specific emission rate, the capacity adjustment is wholly ineffective at correcting the error. If EPA proceeds with this allocation methodology, it should throw out the flawed "well-controlled-rate-maximum" concept and allocate based on the "maximum historical baseline emissions."

The proposed compliance deadlines of 2012 and 2014 are unreasonable, unnecessary, and disruptive to compliance planning. EPA should discard the 2012 and 2014 compliance deadlines and should not seek compliance any earlier than 2015. A compliance date any earlier than 2015 is unreasonable since: 1) States need time to exercise their right to develop a State Implementation Plan (SIP); 2) new emission controls cannot be built in 30 months; 3) companies cannot make important compliance planning and investment decisions without regulatory certainty and coordination with the other upcoming environmental regulations; and 4) the existing CAIR program is achieving environmental benefits and is expected to achieve similar benefits to the proposed Transport Rule.

EPA has greatly underestimated the amount of time required to design, permit, construct, and start up new FGDs and SCRs. EPA assumes that a single FGD and a single SCR can be installed in 27 and 21 months, respectively. Southern Company's historical experience has shown that it takes an average of 54 months to install a single FGD and an average of 36 months to install a single SCR. EPA should update its control timing assumptions to reflect a larger and more recent data set. (See Figures 1 and 2 below).

The proposed Transport Rule suffered from numerous errors in methodologies and numerous incorrect data and assumptions which impacted every aspect of the proposed Transport Rule. Commenting on the proposed Transport Rule was exceedingly difficult given 1) the unreasonably short time allowed for public comment, 2) the lack of clarity provided for EPA's methodology, 3) the numerous flaws identified in EPA's data and methodologies, and 4) the fact that EPA continuously added new data to the docket in the form of three NODAs and declined to illustrate how the new information will impact the final rule. EPA should not issue a final rule without allowing commenters the opportunity to comment on the entire package.

Figure 1. Southern Company's Historical Experience Illustrates that 36 Months are Required for a Typical SCR Installation

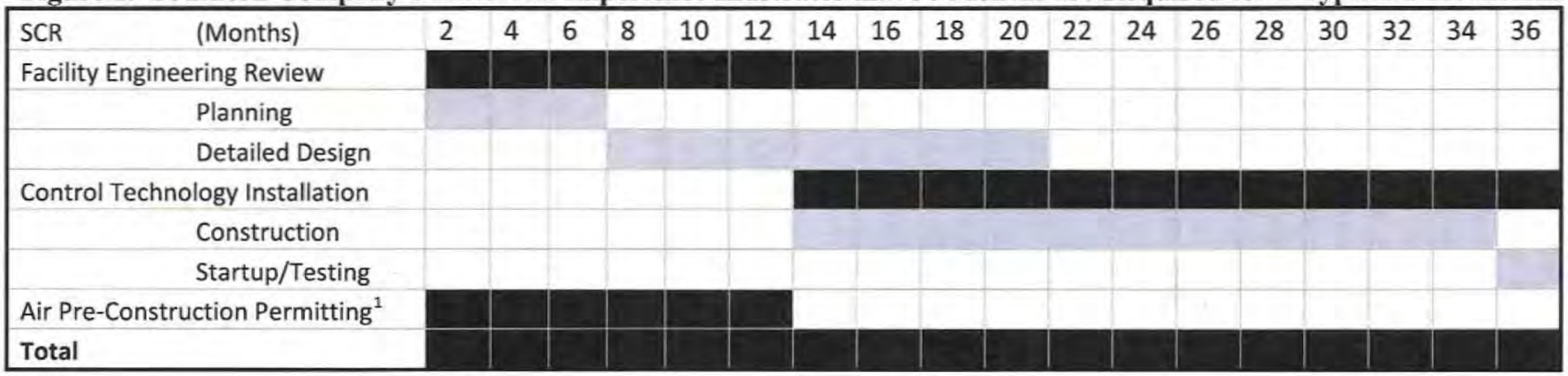
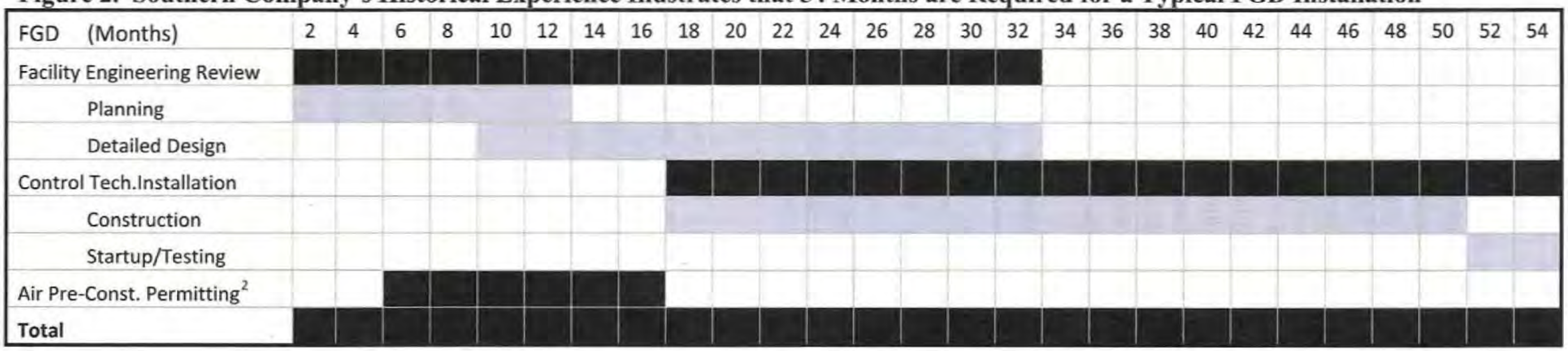


Figure 2. Southern Company's Historical Experience Illustrates that 54 Months are Required for a Typical FGD Installation



[1] This is only non-PSD construction permitting (state construction permits, if necessary). PSD permitting would add length to the overall schedule and likely become a critical path item.

[2] This is only non-PSD construction permitting (state construction permits, if necessary). PSD permitting would add length to the overall schedule and likely become a critical path item.

Attachment 1

Proposed SO2 Allowances Allocations at Southern Company Units

ame and Unit	Unit Type	Capacity (MW)	Emissions (tons)	Transport Rule	Option 1	Option 2
ıit 1	Steam Boiler	125	5,152	1,231	1,513	1,732
ıit 2	Steam Boiler	125	5,244	1,962	1,580	1,808
ıit 3	Steam Boiler	225	8,907	6,308	2,695	3,084
ıit 4	Steam Boiler	350	11,204	6,275	3,554	4,068
ıit 5	Steam Boiler	700	25,032	1,936	7,781	8,907
ıit 6	Combined Cycle	566	6	7	2,741	783
ıit 7	Combined Cycle	566	6	7	2,583	783
Jnit 1	Steam Boiler	700	44,181	2,742	10,734	11,695
Jnit 2	Steam Boiler	700	48,000	1,010	11,299	12,311
Jnit 3	Steam Boiler	880	64,746	2,928	14,117	15,381
Jnit 4	Steam Boiler	880	61,790	3,665	13,567	14,782
Jnit 6	Combustion Turbine	39	0	0	0	0
Jnit 1	Steam Boiler	250	17,708	11,191	3,529	3,845
Jnit 2	Steam Boiler	319	20,355	12,514	4,283	4,667
Jnit 3	Steam Boiler	481	33,670	20,447	6,942	7,564
Jnit 4	Steam Boiler	490	32,828	25,162	6,692	7,291
ı Oil Unit 5	Combustion Turbine	143	10	0		
it 4	Steam Boiler	75	3,757	2,752	510	742
it 5	Steam Boiler	75	3,617	3,041	469	682
it 6	Steam Boiler	320	12,991	2,508	1,728	2,513
it 7	Steam Boiler	500	22,850	3,915	3,070	4,465
g Unit 1	Combustion Turbine	94	1	0	47	46
g Unit 10	Combustion Turbine	94	0	0	61	46
g Unit 2	Combustion Turbine	94	1	0	63	46
g Unit 3	Combustion Turbine	94	0	0	42	45
g Unit 4	Combustion Turbine	94	1	1	65	46
g Unit 5	Combustion Turbine	94	1	0	42	45
g Unit 6	Combustion Turbine	94	0	0	54	46
g Unit 7	Combustion Turbine	94	0	0	36	39
g Unit 8	Combustion Turbine	94	1	0	54	46
g Unit 9	Combustion Turbine	94	0	0	64	46
Init 1	Steam Boiler	500	18,355	0		
Init 2	Steam Boiler	500	17,110	0		
C Unit 3	Combined Cycle	500	6	0		
C Unit 4	Combined Cycle	500	6	0		
Unit 1	Combustion Turbine	199	10	0	54	73
Unit 2	Combustion Turbine	199	8	0	52	73
on Unit 1	Steam Boiler	272	20,342	10,336	2,372	2,715
on Unit 2	Steam Boiler	272	20,958	18,057	2,365	2,707
on Unit 3	Steam Boiler	272	25,733	14,276	2,549	2,918
on Unit 4	Steam Boiler	245	20,771	6,250	2,475	2,833
on Unit 5	Steam Boiler	880	64,663	6,596	8,984	10,284
CC Unit 1	Combined Cycle	1,996	4	4	1,810	783
CC Unit 2	Combined Cycle	1,996	4	4	1,972	879
CC Unit 3	Combined Cycle	1,996	8	8	3,013	945
ı Unit 1	Steam Boiler	60	5,556	2,783	599	686
ı Unit 2	Steam Boiler	60	5,650	3,460	529	605
Unit 10	Steam Boiler	700	41,963	844	6,905	7,904
Unit 6	Steam Boiler	100	10,866	1,074	960	1,098
Unit 7	Steam Boiler	100	11,417	1,157	1,090	1,247
Unit 8	Steam Boiler	165	13,267	177	1,641	1,879
Unit 9	Steam Boiler	165	12,841	333	1,647	1,885

County, Unit GT7	Combustion Turbine	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
County Unit GT8	Combustion Turbine	80	34	0	44	48
County Unit GT9	Combustion Turbine	80	36	0	49	49
nd Unit 1	Steam Boiler	100	6,035	374	1,254	1,366
nd Unit 2	Steam Boiler	100	6,039	157	1,312	1,429
nd Unit 3	Steam Boiler	100	6,149	415	1,329	1,448
nd Unit 4	Steam Boiler	500	29,585	628	6,350	6,919
C Unit 1	Combined Cycle	688	4	4	1,912	905
C Unit 2	Combined Cycle	688	3	3	1,375	904
CC Unit 1	Combined Cycle	78	1	0		
CC Unit 2	Combined Cycle	78	1	0		
CC Unit 3	Combined Cycle	78	1	0		
CC Unit 4	Combined Cycle	78	1	0		
iit 1	Steam Boiler	44	2,101	1,523	819	893
iit 2	Steam Boiler	46	2,119	1,971	783	853
iit 3	Steam Boiler	75	4,275	3,416	1,668	1,818
iit 4	Steam Boiler	116	436	19	70	76
ough Unit 1	Steam Boiler	245	13,983	9,241	3,912	4,262
ough Unit 2	Steam Boiler	245	14,868	10,410	4,050	4,412
ough Unit 3A	Combustion Turbine	39	0	0	0	0
ough Unit 3B	Combustion Turbine	39				
h Unit 1	Steam Boiler	163	8,424	2,992	2,167	2,365
h Unit CT1	Combustion Turbine	80	10	0	20	22
h Unit CT2	Combustion Turbine	80	8	0	20	21
h Unit CT3	Combustion Turbine	80	11	0	24	26
h Unit CT4	Combustion Turbine	80	7	0	18	20
h Unit CT5	Combustion Turbine	80	10	1	24	26
h Unit CT6	Combustion Turbine	80	9	0	21	23
h Unit CT7	Combustion Turbine	80	9	0	20	22
h Unit CT8	Combustion Turbine	80	8	0	25	27
h CC Unit CT10	Combined Cycle	1,377	8	8	4,715	884
h CC Unit CT11	Combined Cycle	1,377	8	8	4,525	884
us Unit 1	Steam Boiler	40	314	0	35	38
us Unit 2	Steam Boiler	75	869	87	76	83
us Unit 3A	Combustion Turbine	52	7	0	3	3
us Unit 3B	Combustion Turbine	52	7	0	3	4
us Unit 3C	Combustion Turbine	52	7	0	3	3
us Unit 4A	Combustion Turbine	54	9	0	3	4
us Unit 4B	Combustion Turbine	54	11	0	3	4
us Unit 4C	Combustion Turbine	54	10	0	4	4
us Unit 4D	Combustion Turbine	54	6	0	3	3
us Unit 4E	Combustion Turbine	54	5	0	2	2
us Unit 4F	Combustion Turbine	54	9	0	3	3
nit 1	Steam Boiler	660	17,158	1,625	8,920	10,210
nit 2	Steam Boiler	660	17,014	1,625	8,783	10,053
Jnit 3	Steam Boiler	660	15,305	1,602	8,565	9,804
nit 4	Steam Boiler	660	15,029	1,607	8,079	9,248
Unit 3	Steam Boiler	125	7,804	1,983	1,438	1,567
Unit 4A	Combustion Turbine	39	1	0	2	2
Unit 4B	Combustion Turbine	39	2	0	2	2
Unit 4C	Combustion Turbine	39	2	0	1	2
ɛr Unit 1	Combustion Turbine	185	11		120	71
ɛr Unit 2	Combustion Turbine	185	11		111	71

nit 1	Steam Boiler	125	[illegible]	[illegible]	[illegible]	[illegible]
nit 2	Steam Boiler	180	11,404	6,408	1,258	1,830
C Unit 3	Combined Cycle	620	14	0	1,679	820
nit A	Combustion Turbine	42	3	0	0	0
A CC Unit 25	Combined Cycle	203	9		845	442
A CC Unit 26	Combined Cycle	485	9		839	442
Jnit 1	Steam Boiler	40	0	0		
Jnit 2	Steam Boiler	40	0	0		
Jnit A	Combustion Turbine	39	0	0		
e CC Unit 1	Combined Cycle	274	4	2	1,834	379
Unit 1	Steam Boiler	865	51,427	3,449	13,490	14,698
Unit 2	Steam Boiler	865	55,286	16,142	13,928	15,175
Unit 5	Combustion Turbine	49	3	2	2	2
CC Unit 6	Combined Cycle	620	4	4	2,307	794
CC Unit 7	Combined Cycle	620	4	4	2,431	791
gton County CC Unit 1	Combined Cycle	123		1	1,417	258
Unit 1	Steam Boiler	75	0	0		
Unit 2	Steam Boiler	75	0	0		
Unit 3	Steam Boiler	112	0	0		
Unit 4	Steam Boiler	250	9,874	0		
Unit 5	Steam Boiler	500	19,655	0		
Unit A	Combustion Turbine	39	0	0		
eorgia Unit 1	Combustion Turbine	153	0	0	122	71
eorgia Unit 2	Combustion Turbine	153	3	0	128	71
eorgia Unit 3	Combustion Turbine	153	0	0	123	68
eorgia Unit 4	Combustion Turbine	150	0	0	59	64
Jnit 5A	Combustion Turbine	59	8	0	3	3
Jnit 5B	Combustion Turbine	59	7	0	3	3
Jnit 5C	Combustion Turbine	59	6	0	3	3
Jnit 5D	Combustion Turbine	59	5	0	3	3
Jnit 5E	Combustion Turbine	59	5	0	3	3
Jnit 5F	Combustion Turbine	59	7	0	3	3
nit 1	Steam Boiler	100	613	175	1,405	613
nit 2	Steam Boiler	100	7,051	4,152	1,320	1,438
nit 3	Steam Boiler	100	6,878	4,119	1,174	1,279
nit 4	Steam Boiler	125	9,214	4,674	1,784	1,943
nit 5	Steam Boiler	125	8,637	4,878	1,659	1,807
nit 6	Steam Boiler	350	22,601	15,016	4,676	5,094
nit 7	Steam Boiler	350	22,989	10,909	4,466	4,866

Attachment 2.

Southern Company comments on Proposed Transport Rule

UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY

COMMENTS OF SOUTHERN COMPANY ON EPA'S PROPOSED RULE ON FEDERAL IMPLEMENTATION PLANS TO REDUCE INTERSTATE TRANSPORT OF FINE PARTICULATE MATTER AND OZONE (75 FED. REG. 45210 (AUGUST 2, 2010))

DOCKET ID NO. EPA–HQ–OAR–2009–0491

SOUTHERN COMPANY
600 NORTH 18TH STREET
BIRMINGHAM, AL 35203

OCTOBER 1, 2010

COMMENTS OF SOUTHERN COMPANY
ON
EPA'S PROPOSED RULE ON FEDERAL IMPLEMENTATION PLANS TO REDUCE INTERSTATE TRANSPORT OF FINE PARTICULATE MATTER AND OZONE
(75 FED. REG. 45210 (AUGUST 2, 2010))

On August 2, 2010 the U.S. Environmental Protection Agency (EPA) published in the Federal Register a proposed rule on Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone (hereinafter referred to as "Transport Rule"). The Proposed Transport Rule is intended to completely replace EPA's 2005 final Clean Air Interstate Rule ("CAIR"), which was remanded to EPA by U.S. Court of Appeals for the D.C. Circuit in December 2008. The court found CAIR to be "fundamentally flawed" and initially vacated the rule, but due to petitions for rehearing the court reversed its vacatur decision, keeping CAIR in place while EPA developed a replacement rule.

The Proposed Transport Rule is similar to CAIR in that it requires emission reductions from electric generating units in the eastern United States in order to satisfy the interstate transport state implementation plan (SIP) requirements of the Clean Air Act Section 110(a)(2)(D)(i)(I). Unlike CAIR, however, the Proposed Transport Rule is structured only as a Federal Implementation Plan (FIP) and provides neither the time nor guidance for states to develop a SIP. According to the proposal, a final Transport Rule will be issued in Spring 2011. Compliance would begin in 2012 and the "assurance provisions" would begin in 2014.

Southern Company is a leading U.S. producer of electricity, generating and delivering electricity to over 4 million customers in the southeastern United States. Southern Company subsidiaries include four vertically integrated electric utilities – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – as well as Southern Power, which owns generation assets and sells electricity at market-based rates in the wholesale market. These subsidiaries operate more than 42,000 megawatts of coal, natural gas, oil, nuclear, and hydroelectric generating capacity. As proposed, the Transport Rule would significantly affect Southern Company's electric generation. Southern Company submits the following comments on the Proposed Transport Rule. Additionally, Southern Company fully supports the comments submitted by the Utility Air Regulatory Group (UARG). Our comments offered below are in addition to the comments submitted by UARG.

Table of Contents

I. Executive Summary

In the two and half years since the U.S. Court of Appeals for the D.C. Circuit vacated the Clean Air Interstate Rule, EPA has developed the proposed Transport Rule. During that time, the Agency has made no effort to obtain stakeholder input on the underlying data used to develop the proposed rule or on the approach.[1] EPA's rush to develop the Transport Rule and its failure to obtain stakeholder input has resulted in a proposed rule that suffers from numerous errors in methodologies and numerous incorrect assumptions. These flaws impact every aspect of this rule: the determination of which states are included in which programs; individual state budgets; unit allocations; timing of emission controls; etc. Although the court did not grant an "indefinite stay" of its CAIR decision, it also expressly declined to impose a schedule on remand. EPA's forsaking quality for purported timeliness is unjustified in light of the fact that CAIR is still in place and the emission reductions mandated by CAIR are providing the intended environmental benefits, as well as helping states attain the NAAQS. For example, Birmingham, Alabama is now attainment for both the ozone and daily $PM_{2.5}$ NAAQS and very close to attaining the annual $PM_{2.5}$ NAAQS.

The proposed rule is voluminous, complex, and opaque, traits which have made commenting on this proposed rule exceedingly difficult. Although the lengthy proposed rule, the accompanying massive amounts of technical supporting information, and the omission in EPA's description of its methodology for developing the provisions of the proposal clearly warrant a comment period longer than 60 days, EPA nevertheless denied our request for a comment period extension. EPA's failure to provide the public with a meaningful opportunity to comment on the proposed Transport Rule is a clear violation of Clean Air Act Section 307(d). Furthermore, EPA recently added new data to the docket, issued a Notice of Data Availability (NODA)[2], and declared that the final rule will be based on the new data in the NODA. However, with the NODA, EPA has provided only a portion of the data needed to evaluate its implications and has declined to illustrate how it will affect the final rule. EPA has provided a proposed rule with an inadequate comment period and a proposed rule which contains 1) numerous factual and methodological flaws and 2) provisions which do not reflect the newly revised information upon which EPA intends to rely, yet EPA has indicated it will not release this revised information for comment. Providing meaningful comments on such a "moving target" is problematic. Additionally, Southern Company objects to EPA's proposal to use its percentage-based air quality contribution threshold approach in the current rulemaking -- or in any future interstate-transport rulemaking -- in the absence of a robust technical justification that the resulting thresholds reflect meaningful, and truly measurable, air quality contributions, consistent with the D.C. Circuit's directive in *Michigan v. EPA*.

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[1] EPA did hold one series of "Listening Sessions" in advance of the proposed rule with stakeholder groups in the Spring of 2009. One such session was held with electric utility industry representatives on April 17, 2009. However, at those sessions, EPA provided no insights into its thoughts or plans for the replacement rule. In in response to questions at those Listening Sessions (and in other forums as well), EPA refused to provide any information on its proposed rule. Even now, in the context of the NODA, EPA is refusing to provide requested information. Outside of the one "Listening Session", EPA has offered no opportunity for input from the electric utility industry.

[2] 75 Federal Register, 53613 (September 1, 2010).

Accordingly, EPA must:

1. correct the numerous errors in methodologies and incorrect assumption identified below;
2. determine which datasets will be used to develop the rule (e.g., data from the NODA or other datasets);
3. replace the flawed methodology with a corrected methodology and reapply using the corrected data; and
4. issue a supplemental proposed rule—properly structured, one more reflective of the technical basis for the final rule, more clearly explained, with documented assumptions, and accompanied with all supporting data —with an adequate time for public comment.

In addition to the methodological flaws, Southern Company believes that the Proposed Transport Rule compliance dates of 2012 and 2014 are unreasonable and unjustified. **EPA should not seek a compliance date any earlier than 2015.** Southern Company strongly recommends that EPA discard the 2012 and 2014 compliance dates since among things, CAIR is still achieving important emission reductions and the absence of any court-ordered remand schedule enables EPA to exercise its discretion to set reasonable compliance dates. Additionally, Southern Company's analysis of the data shows that CAIR achieves virtually the same benefit as the proposed Transport Rule. The proposed compliance schedule is problematic since most states, if not all, will not have time to develop a SIP alternative to replace the FIP proposed by this rule; utilities will be faced with the extremely difficult task of developing and implementing several entirely new allowance strategies from unknown new allowance markets; implementation of fuel switching or the installation of new emission controls will be difficult if not impossible; and the compliance dates are uncoordinated with expected EPA regulations and are disruptive to compliance planning.

For these reasons and the reasons explained below, EPA must issue a corrected supplemental proposal with adequate time for public comment. The compliance date should be no earlier than 2015, with CAIR remaining in place until the compliance date. Further information on the compliance timing, as well as other important issues that must be resolved before issuance of the final Transport Rule, are discussed in the comments below.

II. EPA Deprived the Public of a Meaningful Opportunity to Comment on the Proposed Transport Rule, a Clear Violation of Clean Air Act Section 307(d)

On August 26, 2010 after working diligently to review the proposed transport rule, Southern Company requested an extension of the public comment period from October 1 to November

30.[3] Because of the complexity and lack of clarity on many aspects of the proposed rule and the many issues addressed, we found that 60 days was inadequate to thoroughly understand the rule, reproduce EPA's calculations, and provide meaningful comments. Southern Company noted in our request that reviewing EPA's 3 proposed regulatory options, the more than 20 technical support documents, the more than 90 issues that EPA requested comment on, and the numerous modeling files required more than 60 days. EPA denied our extension request on September 10.

Clean Air Act section 307(d) sets out detailed procedures that EPA must follow in conducting certain Clean Air Act rulemakings, including the ongoing rulemaking to adopt the regional transport rule proposed on August 2, 2010. In particular, section 307(d) rulemakings impose on EPA's Administrator the obligation to accompany any proposed rule with a "statement of its basis and purpose." The statement of basis and purpose must also include information on (a) the factual data on which the proposed rule is based; (b) the methodology used in obtaining the data and in analyzing the data; and (c) the major legal interpretations and policy considerations underlying the proposed rule. See section 307(d)(3). Lacking this information, it is difficult for members of the public to understand what they are being asked to comment upon, and if they do not understand it, then they are essentially deprived of a meaningful opportunity to comment on an EPA proposed rule.

When EPA proposed its transport rule on August 2, 2010, it presented a mountain of information: the rule itself covers 256 pages of the Federal Register, and EPA posted numerous additional background documents on its website. Quantity of information, however, does not equate to quality of information. And the section 307(d) criteria are not met if the Agency's explanation for its proposed rule is confusing and overly complicated, prompting numerous inquiries as to the methodology that the Agency used and policy choices the Agency made before arriving at the approach it took in its proposal.

In the case of the Proposed Transport Rule, EPA has failed to meet its Clean Air Act section 307(d) obligation to provide to the public a clear statement of the methodology that the Agency used and policy choices it made in developing its proposal. Specifically, in order for Southern Company to be able to comment meaningfully on EPA's proposal, it was necessary for us to not only to review the proposal and supporting documentation but also to have at least eight, sometimes lengthy, conversations with Agency personnel and to devote over 100-person hours in analyzing and developing an adequate understanding of the Agency's documentation to be able to replicate their methodology, on just the so-called Air Quality Assessment Tool alone, not to mention the effort required to understand and replicate EPA's emissions allocation methodology. This Tool is crucial for reproducing the derivations of the provisions of the rule, yet EPA would not release a copy of the Tool. While we sincerely appreciate the assistance we obtained from EPA staff to obtain the underlying data sets and to explain the methodology, such extraordinary efforts should not be required of public commenters in order to begin the process of understanding the Agency's methodology. Yet it took this extraordinary effort and individual attention before Southern Company could begin making the calculations needed to prepare the extensive spreadsheets that in turn allowed us to prepare a coherent -- and much shorter -- explanation of the methodology that EPA appears to have used to both develop its proposal and then choose between the numerous policy alternatives. In essence, Southern Company had to

[3] See attached letter [Attachment A] dated August 26.

spend an inordinate amount of time to re-create the AQAT and replicate EPA's methodology. And it was only at that point in the process that it was possible for Southern Company to begin to be able to provide a meaningful response to EPA's proposal, including recommendations for alternative approaches that might achieve virtually the same results in a more cost-effective way.

The short comment period offered for comments on the Agency's extremely complex proposal means that Southern Company is unable to offer today as detailed an analysis as it would like of the Proposed Transport Rule. And we believe that if it was this difficult for us to parse through all the data in order to start to figure out the true basis for the Agency's proposal, then it was likely more difficult for those that do not have the resources that Southern Company has. With that in mind, Southern Company is submitting key parts of its analysis in the comments it is filing today, including draft versions of its background analysis and spreadsheets (see Attachments D, E, and F, filed separately due to file size limitations). Southern Company will subsequently submit to EPA cleaned-up versions (e.g., fixing labeling errors) of these background analysis and spreadsheets -- both to get EPA feedback on whether the spreadsheets reflect accurately the methodology that EPA followed and to provide a good illustration of the tremendous efforts that had to be taken in order to begin to understand EPA's unwieldy proposal.

Now that Southern Company believes it is finally coming to understand the Agency's methodology in developing the Proposed Transport Rule, Southern intends to continue to evaluate and provide additional comments on a broader range of approaches that EPA could have -- and should have -- offered for comment. Southern Company urges EPA to make more of this information available to others and to allow a formal and more extensive comment period upon the methodology that the Agency used and policy choices the Agency made before arriving at the approach it is now taking in its Proposed Transport Rule.

Southern Company will also be submitting comments on EPA's Notice of Data Availability (NODA) and the underlying data that EPA made available through the NODA, which are due October 15. Because EPA has provided only a portion of the new data needed to evaluate its implications to the final rule and has declined to illustrate how it will affect the final rule, Southern Company's comments will not be complete. EPA must issue a supplemental proposed rule—with an adequate time for public comment—that includes the data and assumptions EPA plans to rely on in the final rule.

III. The Proposed Compliance Deadlines are Unreasonable, Unnecessary, and Disruptive to Compliance Planning

A. EPA Should Discard the 2012 Compliance Date

The January 1, 2012 compliance date is only a mere 6 months after the anticipated issuance of the final Transport Rule. Most states, if not all, will not have time to develop a SIP to replace the FIP proposed by this rule; utilities will be faced with the extremely difficult task of developing and implementing several entirely new allowance strategies in unknown new allowance markets; and even implementing fuel switching or installing low NOx burners at a facility will be virtually impossible. Furthermore, coal procurement strategies, fuel inventory levels, and the system dispatch procedures, which are carefully planned over the long term, may be negatively impacted and may not be able to be adjusted in such a short time frame.

A later compliance date (no earlier than 2015) will allow states to exercise their right to develop their own SIP, something many states, including Alabama, Mississippi, and Georgia have expressed a desire to do. It will also allow new allowance markets to develop and allow utilities to properly evaluate and implement possible compliance options. Further, allowing additional implementation time for the Transport Rule will not significantly alter or delay expected environmental benefits, as CAIR is still achieving important emission reductions and the absence of any court-ordered remand schedule enables EPA to exercise its discretion to set reasonable compliance dates. Finally, a compliance date any earlier than 2015 (the CAIR Phase II compliance date) is not justified since CAIR Phase I is achieving virtually the same benefit as the proposed under the Transport Rule (see Section IV).

B. EPA Should Discard the 2014 Compliance Date

The January 1, 2014 compliance deadline is only about 30 months after the expected final Transport Rule, which is an insufficient amount of time to install Selective Catalytic Reduction (SCR) for NOx control or Flue Gas Desulfurization (FGD) for SO2 control. Even if these controls could be built by 2014, in some states, large investment decisions must be approved through the state Public Service Commission (PSC) processes.

Furthermore, the 2014 compliance date does not represent a coordinated approach with the numerous other upcoming environmental regulations affecting the power sector such as future Transport Rules, Clean Air Act Section 112(d) standards (i.e., IB and EGU MACT), New Source Performance Standards (NSPS), Best Available Retrofit Technology (BART) requirements, Greenhouse Gas (GHG) regulations, as water and ash regulations. Indeed, EPA has acknowledged[4] the numerous upcoming regulations in the Proposed Transport Rule and EPA has stated its intent to coordinate these rules with the "goal of fostering investments in compliance that represent the most efficient and forward-looking expenditure of investor, shareholder, and public funds."[5] Despite EPA's stated intent, the proposed Transport Rule compliance deadlines are not being coordinated with the other upcoming regulations and fail to accommodate the need for coordinating important compliance planning and investment decisions. In the midst of all the uncertainty of the upcoming environmental regulations and the impacts of those rules on the investment decisions, it is difficult for the utilities and the PSCs to determine the best path forward from both a customer and business perspective.

In fact, the 2014 compliance deadline is disruptive to the compliance planning of companies, which were planning for a CAIR Phase II deadline of 2015 and adds costs for little if any overall environmental benefit beyond what CAIR would have accomplished in either Phase I as discussed above or in Phase II (2015) (see Section IV). Because no additional controls can be built before 2014, the proposed Transport Rule requirements in 2014 will greatly increase the compliance cost for utilities (in terms of allowances) over CAIR and the "hard" caps may present a reliability concern. Therefore, EPA should not require a compliance date sooner than that of CAIR Phase II (2015).

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[4] 75 Federal Register 45227-45229 (August 2, 2010).
[5] 75 Federal Register 45227 (August 2, 2010).

A compliance date any sooner than 2015 is unreasonable since: 1) new emission controls cannot be built in 30 months; 2) companies cannot make important compliance planning and investment decisions without regulatory certainty and coordination; and 3) the existing CAIR program is achieving and expected to achieve the similar benefits to the proposed Transport Rule.

IV. EPA's "Remedies" Increase Cost with No Demonstrable Benefit Over CAIR

As part of Southern Company's effort to review the Transport Rule, we attempted to recreate EPA's methodology (see Section II above) and then explore alternative approaches. We used the underlying data sets and AQAT procedures to estimate the air quality improvements that would result from each of the Transport Rule's "preferred" remedies and CAIR Phase I and Phase II emissions levels. To do so we used the emissions for each of the states provided by EPA for 2012 and 2014 under the "preferred" remedy and created similar state-by-state emissions totals representing CAIR Phases I and II. On September 23, 2010, EPA staff provided by email to Southern Company a spreadsheet that contained projected emissions for the 2012 and 2014 "remedies" for all 38 states considered in the proposed Transport Rule. To compare the air quality benefits achieved by the CAIR budgets versus the Transport Rule budgets using our version of AQAT, it was necessary to supplement the documented budgets available from the CAIR final rule to include states that were not considered in CAIR. For those states, we used the baseline EGU emissions from Table 2-5 of the Significant Contribution Analysis TSD for the relevant year.

We used as our criteria the number of monitors that are projected to remain nonattainment or have a maintenance issue after achieving the reductions in each scenario. We assessed the benefit of the emission reductions from all states affected by the proposed Transport Rule (i.e., unlike EPAs method of considering the benefits from emissions reductions from the linked states only). We show that the two programs actually provide similar results (see Tables IV-1 and IV-2 below for both 2012 (vs. CAIR Phase I) and 2014 (vs. CAIR Phase II)).

Table IV-1. Comparison of the Projected Air Quality Benefits From the 2012 Transport Rule Remedy with Benefits Obtained From CAIR-1 for Daily PM2.5, Annual PM2.5 and Ozone

TR 2012 Remedy vs. CAIR-1			
		Number of Monitors Determined To Be	
NAAQS	Scenario	Nonattainment	Maintenance
Daily $PM_{2.5}$	2012 Remedy	1	9
	CAIR-1	2	9
Annual PM 2.5	2012 Remedy	1	2
	CAIR-1	1	1
Ozone	2012 Remedy	7	14
	CAIR-1	8	18

Table IV-2. Comparison of the Projected Air Quality Benefits From the 2014 Transport Rule Remedy with Benefits Obtained From CAIR-2 for Daily PM2.5, Annual PM2.5 and Ozone

TR 2014 Remedy vs. CAIR-2			
		Number of Monitors Determined To Be	
NAAQS	Scenario	Nonattainment	Maintenance
Daily PM2.5	2014 Remedy	1	1
	CAIR-2	1	2
Annual PM 2.5	2014 Remedy	0	1
	CAIR-2	0	1

Note that these similar air quality benefits are obtained from similar emission totals across the affected states and despite significant state by state differences in emissions. See the table IV-3 below for a summary of the emissions comparisons.

Table IV-3. Comparison of CAIR Emissions with Transport Rule Remedies for Annual EGU SO2 and NOx for the 28 States With Transport Rule PM2.5 Emissions Budgets

Annual EGU Emissions					
Pollutant	Metric	2012 Remedy	CAIR-1	2014 Remedy	CAIR-2
SO2	28-State Total (tons)	3,893,870	3,512,223	2,500,003	2,533,244
	Max State Incr (tons)	145,779		76,394	
	Max State Decr (tons)	-91,711		-63,423	
	Max State Incr (%)	51%		66%	
	Max State Decr (%)	-234%		-234%	
NOx	28-State Total (tons)	1,376,312	1,459,401	1,376,312	1,250,488
	Max State Incr (tons)	20,556		37,130	
	Max State Decr (tons)	-22,611		-27,599	
	Max State Incr (%)	29%		41%	
	Max State Decr (%)	-95%		-63%	

As explained elsewhere, the replacement of CAIR with the Transport Rule will increase our costs, create volatility in the allowance markets, and potentially limit our operational flexibility. However, these results indicate that the replacement would provide essentially no difference in the desired air quality result.

V. EPA Should Assess the Air Quality Effects of a Less Restrictive Form of Interstate Trading

As EPA revises the rule and considers a compliance deadline no earlier than 2015, it should also assess the effect of a less restrictive form of interstate trading such as a higher than 10% variability limit as well as trading among group 1 and 2 states. Inherent in the examples in Section IV above comparing the CAIR and the Transport Rule remedies is the assumption that each state achieves the emissions reductions specified (i.e., no interstate trading). However, as shown above, while the overall emissions reductions are very similar across the Transport Rule affected states, the state-by-state differences in emissions between the two scenarios are highly variable, and yet they produce very similar results in terms of remaining nonattainment/maintenance monitors. These results, along with EPA's assessment of the effect of the 10% variability limit, are indicative of the fact that some level of interstate trading can be supported; possibly even unlimited trading (See Table IV-3 above).

In reviewing EPA's variability analysis, we think the approach to variability (using HI from 2002-2008) is somewhat reasonable although not necessarily straightforward. While there are issues with how the EPA determined that 10% (or a tonnage in some cases) was a reasonable variability limit, EPA did evaluate the effect of emitting 10% above the cap on air quality. EPA evaluated two approaches to estimate the variation in downwind air quality at each monitor for daily $PM_{2.5}$ allowed under the Transport Rule in 2014 due to the inherent variability in SO2 emissions. The first approach examined the 1-year variability effects on daily $PM_{2.5}$ concentration when variations in emissions from different states are independent from each other. This is intended to represent "typical" random variations in emissions and the resulting typical variations in air quality that might be seen under the Transport Rule. The second approach examined the "worst" case 1-year scenario for each monitor, when the upwind states with the largest impacts per ton emit at the upper end of the variability limit, while upwind states with the lowest impacts per ton emit below their budgets. This is intended to estimate an upper bound for the effects of emissions variability on air quality.

EPA made the following conclusions about both approaches:
"For both approaches, the effects of the inherent variation in emissions on daily $PM_{2.5}$ concentrations **were estimated to be small**."[6]

EPA's conclusion about Approach #1:
"In conclusion, we found that, even while allowing each state's emissions to randomly vary up to 10% of its budget (the 2-tailed 95% confidence variability level prescribed or many states in the Transport Rule), the combined **downwind air quality impacts were essentially negligible**."[7]

EPA's conclusion about Approach #2:
"These results suggest that even under a "worst case" scenario, where nearby states minimize reductions in emissions, while states far away maximize reduction, the resulting **increases in air quality are small relative to other factors** (i.e., weather)."[8]

[6] TSD, Power Sector Variability, p. 44.
[7] TSD, Power Sector Variability, p. 46.
[8] TSD, Power Sector Variability, p. 47.

As described above and to its credit, EPA did provide a limited assessment of variability on air quality. However, that analysis was too limited in at least two ways. First, EPA should have assessed the air quality effect of an "unlimited" trading scenario. Second, EPA's analysis only looked at the "worst-case" scenario of a state essentially emitting 10% above their budget. Under this scenario, EPA concluded that the increases in air quality were "small". What would a similar analysis of 15%, 20%, 25%, 50%, etc. above the state budget had shown on air quality? EPA has not justified why their criterion did not also look to see if higher variability, or unlimited trading, had an impact on air quality. In fact, our assessment suggests that a higher percentage may be supportable.

VI. EPA's Control Installation Assumptions are Flawed

In the proposed Transport Rule EPA states that it takes approximately 27 months to install a single Flue Gas Desulfurization (FGD) system and 21 months to install a single Selective Catalytic Reduction (SCR) system.[9] The agency further believes that 30 months between the final rule and compliance is sufficient time to install such controls.[10] In developing its timelines, EPA used only two facilities as the basis for its FGD timeline (2 Units at Big Bend Station and 2 Units at Centralia) and two facilities for its SCR timeline (1 unit at Somerset Station and 2 units at Keystone)[11]. As discussed below, EPA's examples and assumptions about FGD and SCR time frames are neither representative nor common. Southern Company's historical experience has shown that it takes an average of 54 months to install an FGD and 36 months to install an SCR. These timelines include all of the steps necessary to plan, design, construct and start up an FGD or SCR system on an existing unit. Although our individual project schedules vary depending on site-specific factors and requirements, none of our FGD or SCR installations have occurred in the timeframes that EPA suggests. Further, none of our FGD or SCR installations were completed within the 30 months that EPA proposes to allow before the 2014 Transport Rule compliance date.

EPA should not base important assumptions—which have regulatory and compliance implications—on such a limited number of installations. The projects that EPA analyzed only represent about one percent of the total historical FGD installations and about two percent of historical SCR installations. Using such a small and outdated sample of installations does not properly account for the variability that exists from project to project. Further, we have information to suggest that some of EPA's "model" projects actually took longer than reported, contain non-traditional procurement practices, and represent abnormally fast installations. For its FGD timeline, EPA used 2 units at Centralia as examples of projects completed in 27 months (Alstom was contracted as part of a consortium to carry out the wet FGD retrofit). In February 2004, Southern Company visited Centralia as part of an internal due diligence effort evaluating different FGD technologies. We noted the following issues with that FGD retrofit:

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[9] Boilermaker Labor Analysis and Installation Timing, USEPA, March 2005.
[10] 75 Federal Register 45273 (August 2, 2010).
[11] "Engineering and Economic factors Affecting the Installation of Control Technologies for Multipollutant Strategies." EPA. October 2002.

- PacifiCorp, the operator and largest owner of Centralia, elected to pursue a "non-traditional partnering approach for the FGD retrofits". EPA seems to have selected projects where existing relationships and/or unique project circumstances were involved when contracting for the environmental projects. This is far from a business as usual approach following a typical utility supply chain process. [Note, too, this same "non-traditional approach" was used in the AES Somerset SCR retrofit as well].

- The contract was let in May 1999 with Unit 1 complete in December 2001 (31 months) and Unit 2 complete in December 2002 (43 months). By Alstom's own project timeline, there was a feasibly study from Jan 1999 - May 1999 to perform a technology assessment. This brings the total project durations to 36 months and 48 months respectively (more in line with Southern Company's average FGD project timelines). It is unclear why EPA chose to use 27 months instead of the full project duration.

It should also be noted that quick installations can result in post-COD issues that were not recognized by the EPA in its timelines. At Power-Gen International in 2002, B&W presented the paper, "SCR System Operating Experience at AES Somerset"[12] in which it noted that the short design, engineering, procurement, and installation time did not allow for an in-depth review of all inter-related subsystems. There were some items that were not optimized for actual operations and required some alterations to achieve. In order to achieve high reliability, the Somerset projects required alterations to and/or replacement of initial equipment.

EPA must ensure that compliance implementation periods and control technology installation assumptions are based on: 1) a larger and more recent representation of installations—taking into consideration that quick installations can result in post-commercial problems; and ; 2) changes in the regulatory landscape since the adoption of CAIR and pending regulations for water and ash management that increase the likelihood of control installations requiring permitting; and 3) schedules that represent the installation of multiple controls at a facility at the same time.

Installing multiple controls at a facility at the same time will result in additional scheduling time. Historically, Southern has never installed a FGD and a SCR on the same unit with less than two years apart. Currently Southern is installing both a FGD and SCR on Plant Scherer Unit 3, but the construction schedule will be longer and more complex than individual control installations because of the simultaneous projects. When installing controls on multiple units, also currently underway for four units at Plant Scherer, issues such as space, access, materials, equipment, and labor availability, and scheduling unit outages in order to maintain system reliability and availability must be taken into consideration. These factors also tend to prolong the construction schedule, and, for Plant Scherer, means the controls can only come online for one unit at a time at a minimum six months to a year apart. Thus, the time between the commercial operation of the first FGD and SCR at Plant Scherer and the fourth and last FGD and SCR is estimated to be approximately three years under an aggressive construction schedule. The total duration for only the construction piece (not including planning, etc.) of installing four sets of FGD and SCR at Plant Scherer will likely approach six years. Further, projects in the future will be more difficult as Southern Company has already completed or is currently constructing the easier, more cost-

[12] Tonn D.P. et.al, "SCR Operating Experience at AES Somerset", Power-Gen International 2002, December 10-12, 2002, Orlando, Fl.

effective projects. As we complete additional projects, we expect the average timeline for both FGDs and SCRs to increase as opposed to decrease. Many of the remaining retrofit projects involve more complex logistical and design issues than previous retrofits.

EPA also did not but should have properly accounted for various environmental permitting considerations related to installation of pollution controls. One common critical path item is the need for new onsite and offsite solid waste landfills because of scrubber installation from both a cost and schedule standpoint. For example, Georgia Power's Plant Scherer recently completed construction of a new onsite landfill for gypsum that took more than six years to complete (from planning and engineering to final product). In this case, planning, permitting, and construction was actually set on an expedited schedule in cooperation with the Georgia Environmental Protection Division. For some facilities, especially older plants, it would be necessary to build landfills offsite. The processes involved in acquiring the necessary land could add an extra two to three years to the process. The cost to build an offsite landfill is in the tens of millions. Additionally, startup delays can occur due to the need to obtain or revise NPDES permits. For example, the startup of Plant Smith SNCRs (Selective Non-Catalytic Reduction) was delayed for months after installation due to issues with water permitting regarding nutrient loading to the Bay. Also, the vacatur of the pollution control project exclusion in 2005 and the recent expansion of the PSD permitting program to include greenhouse gases will likely result in more extensive permitting requirements for various types of control installations. For example, some FGD projects may exceed the significance thresholds for greenhouse gases. In other cases, low NOx burners or SCRs can also lead to small but significant under PSD increases of some criteria pollutants. In both solid waste and air permitting, average timelines for obtaining permits in the near future is expected to increase due to limited state resources, budgets, furloughs, and heavier workloads associated with increasingly complex regulatory requirements.

Figures VI-1 and VI-2 below illustrate Southern Company's average project schedule for a single FGD and a single SCR retrofit (Note: these schedules do not account for multiple control installation occurring at the same facility at the same time). While there are some parts of the project schedule within permitting, engineering and design, and construction that can be overlapped, some must be completed in sequence and cannot be performed in parallel. The timelines below illustrate an average FGD and SCR installation time based on Southern Company's historical project experience and show some of the overlap that can occur. As mentioned earlier, there are further schedule and cost pressures when constructing an SCR and FGD at one unit at the same time, constructing multiple SCRs and FGDs at multiple units at one site at the same time, or when managing major construction programs across many sites at the same time. Such projects would likely incur additional logistical difficulties and increase the overall project duration and cost.

Figure VI-1. Southern Company's Historical Experience Illustrates that 36 Months are Required for a Typical SCR Installation

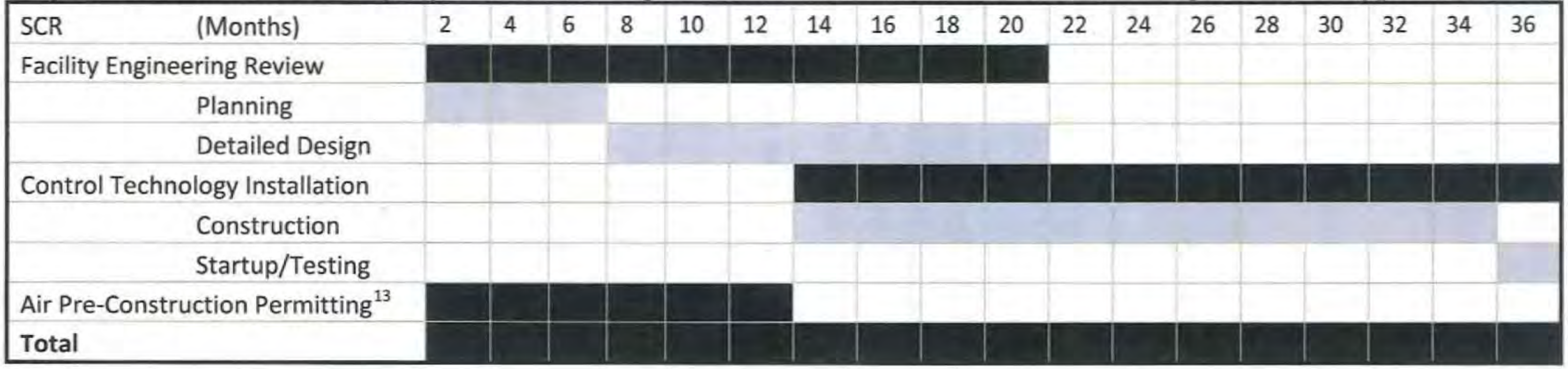

Figure VI-2. Southern Company's Historical Experience Illustrates that 54 Months are Required for a Typical FGD Installation

[13] This is only non-PSD construction permitting (state construction permits, if necessary). PSD permitting would add length to the overall schedule and likely become a critical path item.
[14] This is only non-PSD construction permitting (state construction permits, if necessary). PSD permitting would add length to the overall schedule and likely become a critical path item.

In developing a final Transport Rule, EPA must re-evaluate its timelines to reflect actual experience in the industry and ensure that the timelines it relies on include all of the key steps in the retrofit process, including conceptual design, Request for Proposals (RFP) and bid selection, contract negotiation and issuance, detailed design, environmental permitting (air and solid waste as applicable), mobilization and construction, and start up. For a thorough discussion of these steps, see "Implementation Schedules for Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Process Equipment, Prepared by J. Edward Cichanowicz, October 1, 2010, included with the October 1, 2010 Comments of UARG. The following sections describe Southern Company's specific experience with FGD and SCR retrofits.

A. Southern Company's Experience Installing FGDs Shows That the Average Time Required to Complete a Single FGD is 54 Months

Between 2003 and 2010 Southern Company installed 15 FGDs at the following facilities: Bowen 1-4 (4 FGDs), Wansley 1-2 (2 FGDs), Barry 5 (1 FGD), Gaston 5 (1 FGD), Crist 4-7 (1 FGD), Gorgas 8-10 (1 FGD), Hammond 1-4 (1 FGD), and Miller 1-4 (4 FGD). Our experience shows that the time required to complete a single FGD project ranges from 40 to 69 months, with an average schedule of 54 months. This process includes all of the steps referenced above, from planning to startup.

We have found that executing several of these projects simultaneously can complicate logistics; stress the supply chain for major equipment; and compete for limited craft labor resources - all of which can significantly extend project duration.[15] These factors, as well as location-specific engineering, scope, and retrofit difficulties, account for the large variance in project durations.

1. Southern Company's Quickest FGD Installation Required 40 Months

The FGD at Plant Hammond Units 1-4 (a single FGD vessel serving all four units) was the quickest installation that Southern Company has achieved, and that project took 40 months. Some of the reasons for the shorter-than-average schedule for this project include:

- Typical Southern Company FGD projects would allow time for bidding the project to multiple contractors (i.e., inquiry preparation, bid preparation, evaluation, and contract negotiations) in order to ensure that we receive the best product for prudent cost and dependable service from contractors. The PSC for each state oversees and can disapprove of imprudent expenditures. However, the FGD at Hammond was purchased on a sole source basis and did not require extra time for the bidding process. This approach was made possible by leveraging work from previous projects with the same FGD technology and was a special case in which the Company was able to ensure prudent costs without going through the bid process.

- The shorter execution schedule necessitated "just in time engineering designs" to support the construction effort. While this might be possible, the construction risk factors (cost) are higher due to in-field reworks and errors/omission.

[15] This is true within the Southern Company system as well as competing nationally for resources/equipment.

- One factor that often slows the construction is the limited amount of work space—or site congestion. Specific to the Hammond site, the FGD equipment was located on both the north and south side of the plant's railroad tracks. This relieved site congestion and allowed simultaneous construction of the FGD Island (south side of tracks) from the limestone preparation and gypsum dewatering (north side of tracks). Additionally, the FGD Island was located in an existing parking lot and required minimal relocations and site preparation.

- Although the FGD was completed in 40 months, the expedited schedule had an influence on material availability. We were not able to get our standard & preferred material for the FGD outlet hood and, instead, had to select a lower corrosion resistance material in order to support the schedule. While this has no impact on the performance of the FGD, this section of the equipment may require more frequent maintenance and care in the future.

- Multiple boilers on a single FGD vessel require an open vent stack for draft system protection. Hammond was able to use a stack at one of the existing units that did not require any type of refurbishment, thus decreasing the total project duration. Further, the four units at Hammond were small enough in size to allow all units to be served by a constructing a single FGD vessel. This is not necessarily possible for sites with multiple larger units.

2. Southern Company's Longest FGD Installation Required 69 Months

The FGD at Plant Gorgas Units 8-10 was one of the company's first FGD installations and took 69 months to complete. Some of the reasons for the duration of this project were:

- The Gorgas FGD project was one of our first FGD projects and necessarily required a lot of initial preparation time for developing an inquiry package for the competitive bid process, including supplier qualification (i.e., there was no previous work performed that could be leveraged in an effort to reduce the schedule). Additionally, the commercial negotiations for the contract required several months. Although our more recent experiences have been leveraged to reduce the timing for the competitive bid process, other factors site specific factors make this FGD installation longer than average.

- The Gorgas site required extensive site preparation. An entire mountain had to be removed to create an available footprint for the FGD Island.

- Because this FGD included three units, the retrofit for units 8 and 9 required the ID fan manifold to be replaced, which would not be typical for most retrofits.

- Southern Company overlaps phases of construction and installation where possible. However, the Gorgas site was very congested and the construction of the new chimney and the Stebbins tile FGD vessel had to proceed sequentially rather than in parallel. This is due to the safety exclusion zone required around the new stack while under construction.

- Similar to Hammond, Gorgas also serves multiple boilers on a single FGD vessel which requires an open vent stack for draft system protection. The Gorgas vent stack required extensive refurbishment including a new flue and a new breach.

B. Southern Company's Experience Installing SCRs has Shown that the Average Time Required to Complete a Single SCR is 36 Months

Between 2001 and 2008 Southern Company installed 15 SCRs at the following facilities: Bowen 1-4, Wansley 1-2, Barry 5, Gaston 5, Crist 7, Gorgas 10, Hammond 4, and Miller 1-4. Our experience has shown that the time required to complete a SCR ranges from 28 to 42 months—depending on the scope and the degree of retrofit difficulty—with an average of 36 months. Like FGDs, these schedules include all of the steps described above from planning to startup.. In addition to the factors listed above for FGD projects, we have also found that the difficulty of retrofit integration of the SCR with the boiler and the type/number of unit outages required to complete the project can significantly impact project duration. These factors and location-specific engineering difficulties account for the large variance in project durations.

1. Southern Company's Quickest SCR Installation Required 28 Months

Southern Company shortest schedule duration for installing an SCR is 28 months (Plant Hammond Unit 4). Some of the reasons for this shorter-than-average schedule include:

- Hammond 4 is on the end of an existing power block building. This location provided the unique arrangement to allow the SCR to come off the side of the unit as opposed to going straight back behind the unit, where it is typically more congested.
- This side arrangement allowed construction of the SCR to proceed during normal operation of the unit. However, while the overall project duration was on the shorter end of the range, the unit required a long tie-in outage (78 days) in order to complete the gas path tie-in work.
- Hammond Unit 4 was one of the unique plants where minimal induced draft fan upgrade and very little electrical infrastructure work was required to accommodate the additional draft loss of the SCR. This is not typical.
- At the time of the SCR retrofit, the Unit 4 electrostatic precipitator had been completely refurbished and, therefore, did not require additional structural analysis and strengthening.
- It should be noted that while Hammond 4 had one of the shorter duration schedules, the compressed schedule, aimed at meeting regulatory deadlines related to ozone nonattainment in Atlanta, necessarily had a significant impact on the costs of the project due to a number of factors, such as using two cranes vs. one crane and managing construction labor and resources.

2. Southern Company's Longest SCR Installation Required 42 Months

The SCR at Plant Gaston Unit 5 was one of the longer duration projects Southern Company has installed, and that project in total took 42 months. Some of the reasons for the long duration of the project were:

- The addition of new induced draft fans (balance draft conversion) in order to overcome the additional draft loss of the SCR. With the addition of the new fans, the entire draft system is changed from positive pressure operation to negative pressure operation, thus requiring a structural review and stiffening of the entire draft train.

- The addition of new fans also required creation of extensive electrical infrastructure – starting in the substation with new transformers all the way to the new large horsepower fan motors.

- When Gaston Unit 5 was built, the designers placed the plant close to the river in order to save money on cooling water piping. The close proximity of the unit to the river severely increases the site congestion and dictated the construction plan. In the case of plant Gaston, a very large crane was placed that was able to "reach in" from the side of the power house in order to complete construction. Unfortunately, this fact also dictated that the SCR be "stick built" as opposed to modularized construction.

- The congested work area of the SCR also required working around existing equipment. For example, the SCR inlet ductwork spans over the main coal conveyor (which feed all five units) which runs across the back side of the plant. Additionally, subsurface foundations have to be sited around existing equipment such sumps and cooling water pipes.

- The existing stack required a new breach on the opposite side in order to accommodate the new ID fan addition. This required the existing breach be closed and a new breach be opened in the span of the same outage.

C. Summary and Conclusions

In summary, EPA has greatly underestimated the amount of time that it takes to design, permit, construct, and start up new FGDs and SCRs. It will take longer than 30 months -- in some cases significantly longer than 30 months -- to complete the retrofits of FGD and SCR units at existing EGUs. While considering a compliance date no earlier than 2015, EPA must also update its control installation assumptions taking into account 1) a larger and more recent representation of installations—taking into consideration that quick installations can result in post-commercial problems; and 2) changes in the regulatory landscape since the adoption of CAIR and pending regulations for water and ash management that increase the likelihood of control installations requiring permitting; and 3) schedules that represent the installation of multiple controls at a facility at the same time.

VII. EPA's Fuel Switch Assumptions Are Flawed

EPA made the assumption that coal switching within the bituminous coal grades will have relatively little cost or schedule impact on most units and has requested comment on this issue.[16] EPA's assumption is flawed because coal switching occurs over a longer timeframe than EPA has assumed; this is due to how coal purchases are layered in over time, the time it takes for plants to tune operations to the new fuel as well as the ability of the coal market to accommodate such a large switch as has been assumed. Currently, about two-thirds of Southern Company's required coal supply for 2012 is under contract; and this percent will likely increase prior to issuance of the final Transport Rule. Because of the layering approach that is common in the industry, new long-term contracts are negotiated well before existing contracts expire. Southern Company's coal procurement evaluations and decisions factor in the current and/or projected value of sulfur, which will necessarily change after the final Transport Rule is issued and new SO_2 allowances enter the market. Because the allowance price discovery for SO_2 will not be possible until the second half of 2011 at the earliest, the lead time to assess true costs of procurement decisions for 2012 and beyond will be severely limited. (A spring 2011 Long Term purchase may include purchases not only for 2012 but potentially for 2013, 2014, and 2015, etc). Although coal contracts typically include clauses allowing us to be released from our contractual obligations in the event of a significant regulatory change, these clauses are narrow in nature and could not be relied on to release the Company from the obligation to purchase a large number of contracted tons. Exercising such a clause could be costly, time consuming, and potentially detrimental to coal producers. Of additional concern are rail and barge transportation contracts which are negotiated independently from coal contracts and would have to be revised or terminated on an extremely short time frame if the coal supply associated with those agreements is reduced or eliminated. This could also prove to be a costly and inefficient process. Furthermore, cancelling contracts of this magnitude invites protracted and expensive litigation.

Even the most straightforward coal switches can take well over a year to implement. A typical timeline for a "simple" coal switch would follow the steps below:

1. 4 – 6 months to procure test fuel; (4 – 6 months cumulative)
2. 1 – 4 months test burn; (5 – 10 months cumulative)
3. 2 – 3 months data evaluation; (7 – 13 months cumulative)
4. 2 – 6 months to procure first production fuel; (9 – 19 months cumulative)
5. 2 – 6 months for delivery of production fuel; (11 – 25 months cumulative)
6. 3 to 5 years for existing contracts to expire and achieve 100% switch (47 – 85 months cumulative)

Furthermore, EPA's assumption that national coal markets can shift large volumes of production from higher sulfur grades to lower sulfur grades by 2012 is unreasonable and impractical. First, mine operators are currently reeling from the recession, and many cannot absorb additional costs associated with shutting-in existing production sites and opening new sites or expanding existing sites. Second, lead times, costs and regulatory challenges associated with permitting and starting operations at new mines or increasing production at existing mines may be insurmountable by

[16] 75 Federal Register, 45273 (August 2, 2010).

2012. And lastly, the ability for transportation infrastructure and capacity to absorb large volume swings in such a short time frame is uncertain.
EPA's assumptions indicate that it believes the power, transportation, and coal industries can stop and turn their operations on a dime. These assumptions reveal EPA's complete lack of appreciation for the scale of these operations and the complex, long-term planning these industries must employ.

VIII. The Proposed Transport Rule Should Not be Structured as a FIP

As explained more fully in UARG's comments, the Clean Air Act does not give EPA the authority to promulgate a FIP before allowing the states to submit a SIP. The opportunity to replace a FIP with a SIP at some point in the future does not satisfy EPA's obligation to provide states an opportunity to craft their own plans at the outset of the program. EPA may issue a FIP, "rescind[ing] state authority," only after a state fails to develop and submit a complete SIP and receive Agency approval of it.[17] The Act grants no authority to EPA to promulgate a FIP without first giving the states adequate time and a real opportunity to develop and submit SIPs that reflect each state's "sensitive . . . choices" on how to implement section 110 (a)(2)(D)(i)(I). EPA has no authority to leapfrog over the SIP process and impose its own choices on states and regulated parties.[18]

IX. EPA Must Consider Market Continuity as it Transitions from CAIR to the Proposed Transport Rule and Any Future Transport Rules

EPA has requested comment on how the transition from CAIR would occur.[19] One of our main concerns with the proposed transition from CAIR, is the proposed elimination of banked allowances and the uncertainty that such elimination creates for compliance. There are no markets yet for Transport Rule allowances, and those markets will not exist until September 2011, just before the January 2012 compliance date. As discussed in more detail in Section X, the data used to develop unit allocations in the proposed rule are so flawed and will require such substantial revision that industry is essentially blind to potential compliance challenges. Given the limited trading and industry-wide allocation uncertainty, it is unclear whether allowances will be available if needed. And the Transport Rule's proposed tight compliance schedule exacerbates the uncertainty.

Southern Company supports an approach that would recognize the value of banked NO_x and SO_2 allowances. EPA should recognize the potential loss to utilities—and the eventual cost to customers—by devaluing or eliminating a company's allowance inventory. At a minimum, EPA should include a mechanism the conversion of CAIR NO_x into the Transport Rule program. This would be technically easy to accomplish since EPA proposes to use the same Allowance Management System that it used for CAIR. The conversion of banked CAIR allowances will ensure market continuity through 2011 and will avoid potential price shocks of resetting three new markets simultaneously in the second half of 2011. Subsequently, market continuity will

[17] CAA § 110(c)(1).
[18] Michigan v. EPA, 268 F.3d 1075, 1084 (D.C. Cir. 2001).
[19] 75 Federal Register, 45336 (August 2, 2010)

ensure that reductions achieved under CAIR will continue through 2011 and avoid any incentive to "use up" CAIR allowances and produce a short-term increase in NO_x emissions (the same is also true for Acid Rain SO_2 allowances). The *North Carolina* decision found flaw with use of fuel adjustment factors in determining original CAIR NO_x allowance allocations, however nothing in the decision prohibits the use of existing banked allowances in a new program. In the event that EPA determines the legal concerns are too great to carry the bank forward at full value, Southern Company could support an alternative approach allowing banked allowance conversion at a discounted value. EPA should design a process that effectively eliminates fuel adjustment factor effects by applying a surrender ratio based on the fuel mix of the surrendering entity. To avoid use of conversion proxies (financial institutions on behalf of utilities), allowances could be converted in rounds, with utilities surrendering in the first round followed by a non-utility surrender round. The second round would receive the highest conversion rate applied in the first round, thereby ensuring incentive for utilities to participate in the first round and not utilize conversion proxies. This discounted conversion approach is not preferable, but would achieve some of the objectives of market continuity outlined above.

EPA has stated that future transport rules "may be needed to address transport under future revised ozone or fine particle health standards."[20] Subsequent phases of the Transport Rule should ensure market continuity by maintaining a common currency, allowing use of existing allowances from one phase to the next. A market based program cannot be expected to work if the currency is continuously changing and price signals are disrupted on a regular basis. Further, EPA should wait to see the effect of the current rule before promulgating future transport rules.

X. EPA Used Many Inaccurate Inputs and Assumptions for—and Unrealistic Outputs from—EPA's Integrated Planning Model (IPM)

Note that while EPA made numerous errors in assumptions on emission rates, control technologies and other parameters, we are not including comprehensive specific comments on those errors since EPA has already proposed new data through the NODA. Some of the errors identified to date are listed below.

A. EPA Made Many Assumptions in NEEDS 3.02 Regarding Individual Units that Are Inaccurate

Our review has found that EPA incorrectly characterized a number of the existing dispatchable FGDs for some of Alabama Power Company's units as not existing until 2012:

- Barry, located in Mobile County Alabama, commissioned a wet scrubber for Unit 5 in February 2010.
- Gaston, located in Shelby County Alabama, commissioned a wet scrubber for Unit 5 in February 2010.
- Gorgas, located in Walker County Alabama, commissioned a wet scrubber for Units 8, 9, and 10 in January 2008.

[20] 75 Federal Register, 45227 (August 2, 2010).

- Miller, located in Jefferson County Alabama, commissioned a wet scrubber for Unit 2 in April 2010.

Additional Inaccurate Assumptions in NEEDS 3.02:

- Greene Co Unit 1, located in Greene County Alabama, is a wall-fired boiler. The NEEDS v 3.02 incorrectly categorizes this unit as a cell-fired boiler.

- Scherer unit 4 is incorrectly identified in NEEDS as requiring a FGD in 2011. The SCR and FGD for Scherer Unit 4 is required by the Georgia Multipollutant Rule December 31, 2012.

- SCRs at Scherer units are required to run only during the ozone season and are thus dispatchable outside of ozone season.

- Yates fuel is identified as "Coal Steam" instead of bituminous coal. It is unclear whether this error leads to an unexplainable inconsistency in SO2 emission rates for these units in the modeling.

- Jack Watson Units 4 and 5 in Mississippi are shown to have existing SNCRs. There are no SNCRs installed or planned at these plants.

- Daniel Units 1 and 2 in Mississippi are shown to have existing SNCRs. There are no SNCRs installed or planned at these plants.

- Crist Unit 4 and 5 located in Escambia County, Florida. NEEDS v 3.02 incorrectly lists these units having Low NOx Burners (LNB) for NOx control. Crist Units 4 and 5 have low NOx burner tips which are not considered LNB technology.

- Crist Unit 6 located in Escambia County, Florida. NEEDS v 3.02 incorrectly lists the unit has OFA. *(The unit does not have a functioning OFA system.)*

- Crist Unit 7 located in Escambia County, Florida. NEEDS v 3.02 incorrectly lists the unit as "no post NOx controls". Crist Unit 7 is controlled with a SCR. Startup was April, 2005.

- Crist Units 4,5,6 and 7 located in Escambia County, Florida. NEEDS v 3.02 incorrectly lists these units as "not controlled for SO2". Crist Units 4-7 are controlled by a common FGD scrubber. Startup was December, 2009.

- Smith Unit 1 located in Bay County, Florida. NEEDS v 3.02 incorrectly lists this unit as having Low NOx Burners (LNB) for NOx control. Smith Unit 1 has low NOx burner tips which are not considered LNB technology.

- Smith (Combined Cycle Unit) Units 3A, 3B and 3S located in Bay County, Florida. NEEDS v. 3.02 incorrectly notes the capacity as 158 MW, 158 MW, 166 MW, respectively. The Summer Net Capability of Smith 3A,3B,3S is approximately 175 MW, 175 MW and 206 MW.

B. EPA Made Many Assumptions in IPM Regarding Individual Units that Are Inaccurate

Below are errors identified in the IPM Modeling Inputs. Most of the errors we have found in IPM model files are related to the Georgia Multipollutant Rule (see Attachment A) and timing of controls.

- Plant Harllee Branch Unit 1- IPM Assumes (in the 2014 base case) an FGD and SCR to be in place by 2014 (assuming this is January 1, 2014). The Georgia Multipollutant Rule requires that these be in place by December 31, 2014.

- Plant Harllee Branch Unit 2- IPM Assumes (in the 2014 base case) an FGD and SCR to be in place by 2014 (assuming this is January 1, 2014). The Georgia Multipollutant Rule requires that these be in place by December 31, 2014.

- Plant Harllee Branch Unit 4- IPM Assumes (in the 2014 base case) an FGD and SCR to be in place by 2014 (assuming this is January 1, 2014). The Georgia Multipollutant Rule requires that these be in place by June 1, 2014.

- Plant Yates Unit 6- IPM Assumes (in the 2014 base case) an FGD and SCR to be in place by 2014 (assuming this is January 1, 2014). The Georgia Multipollutant Rule requires that these be in place by June 1, 2015.

- Plant Yates Unit 7- IPM Assumes (in the 2014 base case) an FGD and SCR to be in place by 2014 (assuming this is January 1, 2014). The Georgia Multipollutant Rule requires that these be in place by June 1, 2015.

- Plant Scherer Unit 1 - IPM Assumes (in the 2014 base case) an FGD and SCR to be in place by 2014 (assuming this is January 1, 2014). The Georgia Multipollutant Rule requires that these be in place by December 31, 2014.

- Plant Crist Unit 4-7 – IPM Assumes no FGD to be operated. Crist Units 4-7 are controlled by a common FGD. Startup was December, 2009.

- Plant Crist Unit 6 – IPM Assumes no SCR to be in place by 2014. Crist Unit 6 SCR is under construction. Startup in 2012.

C. IPM-Modeled Outcomes Do Not Reflect Actual Source Operations

Although not explicitly explained, IPM predicted that the vast majority of dual fuel units would run exclusively on natural gas. Therefore, EPA did not allocate any SO2 allowances to dual fuel units. Apparently, IPM concluded that it was most "economical" to run these units on natural gas and failed to consider seasonal constraints on natural gas supply (e.g., shortage of supply during the winter months). For example, IPM modeling assumes the Plant McManus will burn natural gas in 2014, and yet we have no plans to do so. Plant McManus is not currently permitted to burn natural gas and does not even have a current gas supply. Also, the "preferred" remedy IPM cases for 2012 and 2014 show Plant McManus not operateing at all (e.g., no heat input and no emissions). Georgia Power conducted a study on conversion to natural gas thirty years ago that found that while an existing natural gas line was near the plant site, the supply from that line would not be adequate for the plant. The study has not been updated recently. Suppliers also generally ask for a commitment to consume a certain amount of natural gas, which we may be unable to do considering McManus is a peaking facility. Conversion to natural gas would also involve building a gas lateral from the supplier's lines, which we may or may not be able to accomplish quickly. Additional cost and schedule considerations involved in building a gas lateral include acquiring right-of-way property and potential permitting activities. In summary, there are no plans to convert McManus to natural gas by 2014 and, because of potential regulatory permitting and technical limits of the existing pipeline, it is unlikely that it is possible to do so in that timeframe.

Below are additional errors identified in the IPM-Modeled outcomes.

- IPM assumes as a control strategy "early retirements" for McManus (1 & 2), Watson (1 & 3), and Sweatt (1 & 2). The "preferred" remedy IPM case in 2012 and 2014 does not project that any of these will operate (e.g., no heat input and no emissions). Retirement of any unit is a complex decision based on projected need, transmission requirements, reliability requirements, and cost. An assumption by IPM of an early retirement of a unit may be greatly flawed and should not dictate future allocations for that unit. The Company currently has no plans to retire these units.

- When compared to recent historical data, there appear to be some assumptions for switching to lower sulfur coals within grade for certain units in the 2012 base case. We will defer our detailed comments for the NODA comment period. However, in particular, the SO2 emission rates for Plant Yates Unit 2-7 all appear to be much lower than recent actual SO2 emission rates and may indicate a switch to lower sulfur coal within grade (or may be due to incorrect fuel assignment of "Coal Steam" in NEEDS). Some other units, such as Kraft and McIntosh also appear to have lower SO2 rates than recent actual, although the differences are less drastic than Yates. As noted earlier, even simple coal switches can take years to implement. The emission rates assumed for these three plants imply an average bituminous coal sulfur content in the 0.6-0.7% range, for which such considerations as coal availability and supply reliability, transportation availability, and cost become extremely important.

XI. EPA's Method for Determining States' Significant Contribution to Nonattainment and Interference with Maintenance is Arbitrary and Unjustified and Results in Unnecessary Requirements for Emissions Controls

A. EPA's Base Case Modeling Should Have Included CAIR

The Proposed Transport Rule fails to account properly for post-2005 emission reductions and air quality improvements resulting from CAIR.[21] EPA's decision to assume that CAIR is not in effect for its analysis of the 2012 and 2014 base cases has the effect of greatly overestimating EGU emissions during those periods. EPA should have included CAIR in its base case because it remains binding law pending the promulgation and effective date of a replacement rule. The D.C. Circuit granted EPA's petition to remand CAIR without vacatur, holding that "notwithstanding the relative flaws of CAIR, allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values covered by CAIR."[22] By the terms of the court's opinion on rehearing, CAIR will be in place until a replacement rule is implemented. Thus, there is no time during which neither CAIR nor a replacement rule will be effective.

In the proposed rule's preamble itself, EPA recognizes what it could hardly dispute -- that CAIR has yielded substantial emission reductions. For example, according to the proposed rule, the most recent monitoring available (2006-2008) "shows significant improvement[]" in $PM_{2.5}$ ambient air quality, and "EPA believes that a great deal of the improvement in $PM_{2.5}$ annual and 24-hour concentrations in the eastern U.S. can be attributed to EGU SO_2 reductions achieved during CAIR."[23] There can be no dispute that CAIR, together with other programs, has had significant effects in reducing NAAQS design values.

Additionally, in both the NOx SIP Call and CAIR rulemakings, EPA took account of other regulations in evaluating downwind air quality. *See* 63 Fed. Reg. at 57377/1 (NOx SIP Call) (EPA's "analytical approach assumes that downwind areas implement all required controls and receive the benefit of reductions from Federal measures, and yet have a residual nonattainment problem."); 69 Fed. Reg. at 4581/2-3 (CAIR proposed rule) ("In modeling the 2010 and 2015 'base cases,' we took into account adopted State and Federal regulations (*e.g.*, mobile sources rules, the NOx SIP Call) as well as regulations that have been proposed and that we expect will be promulgated before [CAIR] is finalized.") Additionally, in the Proposed Transport Rule, EPA took into account all other federal rules promulgated as of December 2008, *except for CAIR*.[24] It is difficult to understand why EPA made the decision to ignore CAIR for purposes of the Proposed Transport Rule.

EPA's brief explanation of why it decided to ignore CAIR in modeling the base case for the proposed rule, which it characterizes as "a unique situation," is baffling. EPA acknowledges that "EPA has been directed to replace the CAIR; yet the CAIR remains in place and has led to

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[21] 75 Federal Register, 45233 (August 2, 2010).
[22] 550 F.3d at 1178.
[23] 75 Federal Register, 45219; see also id. at 45220/1-3 (noting that "EPA believes that there would be substantially more nonattainment counties for both the annual and 24-hour standards if the CAIR were not in effect," and crediting a variety of programs with improved ozone air quality in the years since EPA published CAIR).
[24] 75 Federal Register, 45233 (August 2, 2010).

significant emissions reductions in many states." Then, it says that "EPA cannot prejudge at this stage which states will be affected by the rule," and goes on to note that sources in states that are regulated under CAIR but not under the Transport Rule may increase their emissions once CAIR expires. Yet there are very few of those states, and the existence of a minority of such states hardly justifies wholesale disregard of CAIR reductions.[25] In any event, many sources located in states that were regulated under CAIR but are not proposed to be regulated under the Transport Rule have gone to great expense to install controls to comply with CAIR. They are very unlikely to dismantle them or to discontinue use of them to the point that their emissions return to pre-CAIR levels. Finally, $PM_{2.5}$ and ozone concentrations have declined substantially in recent years, due not only to CAIR but a combination of other programs, and are expected to continue declining in the future.[26] While it may be true that some limited increases in emission levels could occur due to discontinuation of CAIR requirements in some states, it is far less realistic to assume that CAIR is no longer in effect than to assume that it remains in effect. EPA should recalculate the 2012 and 2014 base cases to take CAIR into account.

B. EPA's Significant Contribution Analysis and Process to Classify Certain States as "Group 1"or "Group 2" States is Inadequately Explained and Misguided

In the Proposed Transport Rule, EPA describes its process for classifying states as "group 1" and "group 2" states for $PM_{2.5}$ as follows:

> *EPA used the air quality assessment tool to analyze the impact of requiring all states linked to the downwind state site with an air quality problem, as well as the downwind state, to reduce emissions consistent with the levels discussed for 2012 . . . previously. The air quality assessment tool shows that those 2012 reductions will resolve the nonattainment and maintenance problems for all of the areas to which [certain] states [referred to as group 2 states] are linked . . . . EPA also assessed whether, in 2014, the combination of this level of reduction from the group 2 states and the remaining states (referred to as group 1 states) continued to result in all downwind areas—except for Allegheny County, Pennsylvania—fully addressing their nonattainment [and/or] maintenance problems, and determined that it did.*[27]

Conversations with EPA staff have revealed that, while not untrue, this description is incomplete and potentially misleading, especially with respect to the analysis that led to classification of the group 1 states. A representative of Southern Company contacted EPA's Clean Air Markets Division on September 3, 2010, and again on September 10, 2010, requesting clarification regarding how EPA classified individual states as group 1 or group 2 states. A representative of the Clean Air Markets Division explained the process as follows.

[25] *Compare* 70 Fed. Reg. at 25167/1 *with* 75 Fed. Reg. at 45215/2. With respect to the annual $PM_{2.5}$ NAAQS, only Mississippi and Texas were regulated under CAIR but are not proposed to be regulated under the Transport Rule. With respect to the 8-hour ozone NAAQS, only Iowa, Massachusetts, Missouri, and Wisconsin were regulated under CAIR but are not proposed to be regulated under the Transport Rule.
[26] EPA's Trends Report at 1-2
[27] 75 Federal Register, 45282 (August 2, 2010).

EPA first determined which downwind monitors were classified as nonattainment and/or maintenance for $PM_{2.5}$ based on the projected 2012 base case air quality, and then identified upwind states that were "linked" to these monitors. This step in EPA's methodology determined which states were included in the Transport Rule for $PM_{2.5}$, at least as group 2 states, based on their significant contribution to nonattainment or interference with maintenance. Next, EPA used its air quality assessment tool and the emission changes resulting from the 2014 cost curves to evaluate how air quality at the nonattainment and maintenance monitors would change in response to emission reductions from "linked" upwind states, assuming a linear relationship between reductions in the upwind states' emissions and reductions in their respective contribution to projected ambient concentrations at the downwind monitors. EPA evaluated each monitor independently, considering only emission reductions from "linked" upwind states and the state in which the monitor is situated. EPA found that the 24-hour $PM_{2.5}$ NAAQS was controlling because most annual $PM_{2.5}$ problems were resolved at relatively low dollars-per-ton thresholds, while 24-hour $PM_{2.5}$ problems were more likely to persist at higher cost thresholds. EPA focused on the maintenance monitors and did not consider the nonattainment monitors separately because of the way that nonattainment and maintenance sites were determined.[28]

Using its air quality assessment tool, EPA determined that, in 2014, there were six monitors that still showed maintenance problems at approximately \$300-400 per ton that, with the exception of one in Allegheny County, Pennsylvania, could be eliminated at \$2,400 per ton or less. EPA then decided that the states linked to those six monitors that continued to have maintenance problems at higher dollar-per-ton levels should be required to make additional emission reductions and used the 2012 base case to determine which upwind states were "linked" to those six remaining monitors. EPA classified upwind states linked to those six monitors as group 1 states and upwind states not linked to those six monitors as group 2 states. It appears that this was the sole determinant for classifying states as group 1. Strikingly, according to EPA's Clean Air Markets Division, in determining group 1 or group 2 status in 2014, *EPA ignored the air quality benefits that would accrue in 2012 and 2013 from the emission reductions required by the Transport Rule in 2012 and from state rules and consent decrees that require emission reductions by 2014.*

This illogical decision not to consider the results of reductions required beginning in 2012 in projecting remaining maintenance problems in 2014 demonstrates a complete disconnect in the Agency's analysis. EPA characterizes its Proposed Transport Rule as having two "phases." 75 Fed. Reg. at 45215/3. It makes no sense to evaluate phase II of the proposal in isolation, ignoring the projected effects of phase I. EPA's approach is made worse by the Agency's decision to ignore the effects of CAIR for purposes of modeling. *See* section XI-A. Had EPA considered the emission reductions that would result from the 2012 CAIR compliance deadline, it is likely that the maintenance problems projected at most or all of these six monitors in 2014 would not have existed, even if the Agency had continued to ignore the effects of CAIR. Air quality has been improving steadily in recent years, and, consistent with that nationwide trend, 24-hour $PM_{2.5}$ concentrations at all six of the monitors at issue show a strong downward trend.

[28] As described above, EPA determined maintenance sites based on the future-year maximum $PM_{2.5}$ design values, and nonattainment sites based on future-year five-year weighted average annual $PM_{2.5}$ design values. Thus, all nonattainment sites were also maintenance sites. 75 Fed. Reg. at 45247. *See* Section XI-G for comments regarding the manner in which EPA determined maintenance sites.

See Figure XI-1 showing the 98th percentile design values for 24-hour $PM_{2.5}$ at these six monitors from 2003-2008 at Section XI-F. EPA should redo (as well as publish for public comment) its analysis of 2014 air quality by including consideration of the emission reductions required in 2012 under the proposed rule. A balanced analysis of this issue is likely to remove any justification for imposing more stringent SO_2 requirements on certain states in phase II of the program.

C. EPA's Overall Approach Results in a Highly Biased and Stringent Solution

EPA's method eliminated the monitored-plus-modeled test for identifying downwind (and now maintenance) monitors for assessment that was used in CAIR. This change removes an important constraint on the use of uncertain models. EPA's method ignored real emissions reductions from CAIR (still in place and operating) and local SIP-related controls, this omission leads to an overestimate of projected nonattainment/maintenance. EPA's method ignored its own regulatory modeling guidance by not properly projecting future air quality, especially for urban areas with strong local source contributions. For such situations, EPA guidance for evaluating air quality requires the use of refined models such as AERMOD joined with CMAQ for $PM_{2.5}$, or a 4 km or less horizontal resolution receptor grid and/or plume-in-grid treatment for ozone. Collectively, the EPA approach results in over predictions of future air quality concentrations and over predictions of the number of significant air quality contribution linkages, thereby inflating the air quality burden to be "resolved."

By assessing NOx emissions first, the EPA approach incorrectly includes NOx emissions reductions in the Proposed Transport Rule. EPA's own justification for not evaluating emission reductions above $500/ton of NOx was that EPA found that "SO_2 reductions are generally more effective than NOx reductions at reducing $PM_{2.5}$".[29] This produced a high-cost look into SO2 emissions. If SO2 had been assessed first, additional NOx reductions would have been shown to add little additional benefit and therefore be unwarranted. Shown below in Tables XI-1 and XI-2 are results that illustrate this effect using Southern Company's "replicated" version of EPA's AQAT.

[29] 75 Federal Register, 45281 (August 2, 2010)

Table XI-1. Number of Monitors Projected to be Nonattainment or Maintenance for the Daily PM2.5 Standard At $0 to $400 Per Ton of SO2 and $0 and $500 Per Ton of NOx

NOx First vs. SO2 First - 2014 Daily $PM_{2.5}$			
Daily $PM_{2.5}$ - 2014		Number of Monitors Determined to be	
$/Ton SO2	$/Ton SO2	Nonattainment	Maintenance
0	0	40	71
0	500	39	64
100	0	6	16
100	500	5	15
200	0	3	11
200	500	1	9
300	0	1	8
300	500	1	6
400	0	1	7
400	500	1	5

Table XI-2. Number of Monitors Projected to be Nonattainment or Maintenance for the Annual PM2.5 Standard At $0 to $400 Per Ton of SO2 and $0 and $500 Per Ton of NOx

NOx First vs. SO2 First - 2014 Annual $PM_{2.5}$			
Annual $PM_{2.5}$ - 2014		Number of Monitors Determined to be	
$/Ton SO2	$/Ton SO2	Nonattainment	Maintenance
0	0	13	20
0	500	12	19
100	0	3	4
100	500	2	3
200	0	2	3
200	500	2	3
300	0	1	3
300	500	1	3
400	0	1	2
400	500	1	1

As it evaluated the effects of ever increasing reductions, the EPA approach assesses only benefits from transported and local EGU reductions and appears to set the criteria for "stopping" as showing attainment/maintenance. This criterion places the entire burden for achieving and maintaining the NAAQS on transported air pollution. Furthermore, by ignoring the role of local controls, at least until the end of the assessment approach, the burden is placed ENTIRELY, and unlawfully[30] on transported and local EGU's. After correcting the errors in its data bases, EPA should redo the analysis and alter its approach by:

- Including local controls in the 2012 baseline, as well as including CAIR in the 2012 baseline.
- Constraining the modeling by requiring both monitoring and modeling in identifying downwind receptors.
- Exploring alternative methods for modeling or post-modeling analysis that strive to obtain the projected air quality contributions from both local and transport, as accurately as possible.
- Focus on SO2 emission reductions first and then assess whether adding NOx emission reductions provides significant benefit.

D. EPA's Refined Air Quality Modeling Fails to Follow its Own Guidance for Application and Performance Evaluation

EPA applied the CAMx model and its OSAT and PSAT source apportionment tools. There are serious problems with their application of these tools that begs the credibility of their analysis.

First, EPA failed to apply their own guidance in modeling for $PM_{2.5}$ in urban areas, especially where local sources have a significant short-range effect on the monitors (e.g., the North Birmingham and Wylam $PM_{2.5}$ monitors in Birmingham both have significantly elevated concentrations compared to nearby urban monitors, largely due to local sources). EPA guidance recommends the use of AERMOD in conjunction with CMAQ (or CAMx) to obtain a more accurate projection of air quality. EPA did not do this nor otherwise try to account for effects of local sources in their projections. By ignoring this issue, EPA has likely overestimated future air quality concentrations, thereby increasing the air quality "burden" that must be resolved, especially since EPA requires attainment and maintenance to be achieved through this rule, a criteria that is both overly burdensome and unlawful.

Second, EPA's model performance evaluation is cursory at best. State SIP demonstrations require model performance evaluations that are far more rigorous. Further, EPA does not even use actual historical EGU emissions to assess how well the air quality model predicts actual historical monitored data. They use "typical" EGU emissions. This process for model evaluation is totally unacceptable. In a model performance assessment, actual historical emissions must be used in the modeling or else the comparison of air quality modeling predictions to actual historical monitored data has no meaning.

Third, given the importance of the PSAT and OSAT tools, EPA should have done much more to demonstrate that the tools give reliable answers, especially since they are being used to assess such small thresholds. A similar demonstration is needed for their use of the CAMx model itself. Can these models and source apportionment tools really give accurate results at differences of 0.15 ug/m3 of PM and 0.8 ppb of ozone?

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[30] See UARG's comments.

Finally, since EPA's approach is to rely solely on the model to determine if a monitor is in nonattainment or has a maintenance issue, getting the air quality projection correct is critical. EPA cannot reasonably argue that the use of coarse-scale modeling is acceptable for "transport" but that "local" effects are not relevant. The ultimate stringency of the proposed rule is critically dependent on getting projected air quality correct, and getting the local contribution correct is an essential element.

E. A Lower Cost Solution Appears Possible for $PM_{2.5}$

It is unclear why EPA chose to drive to such a stringent "remedy" when a lower cost solution appears possible for $PM_{2.5}$. Using the AQAT, focusing on the 2012 cost curves, and assuming that local controls should bear some of the burden, it would appear that a similar air quality benefit could be achieved at between $200 and $400 per ton of SO2. Table XI-3 below shows the results of these costs levels vs. the 2012 remedy.

Table XI-3. Comparison of the Projected Air Quality Benefits From the 2012 Transport Rule Remedy with Benefits Obtained at $100 to $500 Per Ton of SO2 in 2012 for Daily PM2.5, Annual PM2.5 and Ozone

TR 2012 Remedy vs. $/ton SO2			
		Number of Monitors Determined To Be	
NAAQS	**Scenario**	**Nonattainment**	**Maintenance**
Daily $PM_{2.5}$	2012 Remedy	1	9
	$100 SO2	12	27
	$200 SO2	6	16
	$300 SO2	3	14
	$400 SO2	2	11
	$500 SO2	1	8
Annual $PM_{2.5}$	2012 Remedy	1	2
	$100 SO2	5	9
	$200 SO2	3	3
	$300 SO2	2	3
	$400 SO2	1	3
	$500 SO2	1	2

F. EPA's Proposed Air Quality Contribution Threshold is Flawed

EPA proposes to use an air quality contribution threshold based on a percentage -- specifically, one percent -- of the NAAQS for annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and 8-hour ozone to determine whether an upwind state should be included in the Transport Rule program with respect to each of those NAAQS.[31] EPA explains in the preamble to the proposed rule that it chose to deviate from the approach it used in CAIR with respect to $PM_{2.5}$ by using here a two-digit value rather than a single-digit value and "decoupl[ing] the precision of the air quality thresholds [from] the monitoring reporting requirements."[32]

Although EPA properly proposes to avoid setting a zero contribution threshold for the current 24-hour $PM_{2.5}$ NAAQS, and to avoid setting a precedent for a 0.1 μ/m^3 contribution threshold if the annual $PM_{2.5}$ NAAQS in the future is reduced to some value lower than the current NAAQS but higher than 10 μ/m^3 (*e.g.*, 14 μ/m^3), EPA's proposed approach ignores the limits of the capability of its air quality modeling techniques -- and of ambient monitoring -- to meaningfully detect and measure ambient-air contributions at the extremely low levels represented by one percent of current or possible future NAAQS. For example, the numerical values that result from application of EPA's one-percent contribution threshold approach to the current NAAQS -- *i.e.*, 0.15 μ/m^3 for annual $PM_{2.5}$, 0.35 μ/m^3 for 24-hour $PM_{2.5}$, and 0.8 ppb for 8-hour ozone -- are so low that they are likely below the detection capability of existing modeling and measurement tools. For that reason, it is far from clear that these thresholds could be deemed to reflect a "measurable contribution" to downwind nonattainment and maintenance problems, as required by the D.C. Circuit.[33] Interstate contributions cannot be assumed out of thin air.") (emphasis in original). At a minimum, EPA should provide, in a supplemental notice of proposed rulemaking, a technical justification for these very low thresholds as representing meaningfully measurable air quality contributions.

Equally troubling is EPA's indication that it may be planning to use this same percentage-based approach in any future version of the Transport Rule to address possible future NAAQS.[34] Application of this approach to potential future ambient standards that may be even lower than the current NAAQS would produce even less meaningful thresholds. It makes no sense for contribution thresholds to change based exclusively on changing NAAQS levels, irrespective of the capabilities of modeling and measurement technologies at the time the thresholds are established.

Accordingly, Southern Company objects to EPA's proposal to use its percentage-based air quality contribution threshold approach in the current rulemaking -- or in any future interstate-transport rulemaking -- in the absence of a robust technical justification that the resulting thresholds reflect meaningful, and truly measurable, air quality contributions, consistent with the D.C. Circuit's directive in *Michigan v. EPA*.

G. The Method EPA Used To Determine "Interference With Maintenance" in the Proposed Rule Overestimates Actual Future Design Values

The method that EPA used in the Proposed Transport Rule to identify downwind monitors to be included in its "interference with maintenance" analysis overstates actual future design values,

[31] 75 Federal Register, 45237-45238 (August 2, 2010).
[32] 75 Federal Register, 45237 (August 2, 2010).
[33] *Michigan v. EPA*, 213 F.3d at 684 (" . . . EPA must first establish that there is a measurable [air quality] contribution.
[34] 75 Federal Register, 45237 (August 2, 2010). (noting that one of the considerations favoring the one-percent contribution threshold approach is that "the approach is readily applicable to any current and future NAAQS").

probably by a substantial amount. EPA explains in the preamble to the proposed rule that it determined maintenance sites based on the future-year maximum design values, and nonattainment sites based on future-year five-year weighted average annual design values. (Thus, all nonattainment sites were, in effect, also maintenance sites because the maximum design value is always higher than the five-year weighted average.)[35] However, EPA provides no justification for choosing this particular methodology to determine maintenance sites. By using the *future-year maximum* $PM_{2.5}$ design values as the basis for the "interference with maintenance" analysis, EPA fails to take account of the strong nationwide trend toward decreasing design values and improving air quality, which the Agency has said it expects to continue.[36] One can logically assume that EPA attributes the improving air quality to recent ongoing emissions declines and expects air quality to continue to improve as further emissions reductions are made.

This approach had a major effect on the design of the proposed rule. For example, EPA proposed to require certain states (the "group 1 states") to meet additional SO_2 emission reduction requirements beginning in 2014, beyond the reduction requirements for 2012, because of perceived maintenance problems at six specific downwind monitors. Plotted in Figure XI-1 below are the 98th percentile design values for $PM_{2.5}$ from 2003 to 2008[37] based on EPA's 2006-2008[38] Design Value spreadsheet for $PM_{2.5}$, *available at* http://www.epa.gov/oaqps001/airtrends/pdfs/dv_pm25_2006_2008rev102809.xls. The downward trend in design values at these six monitors is clear:

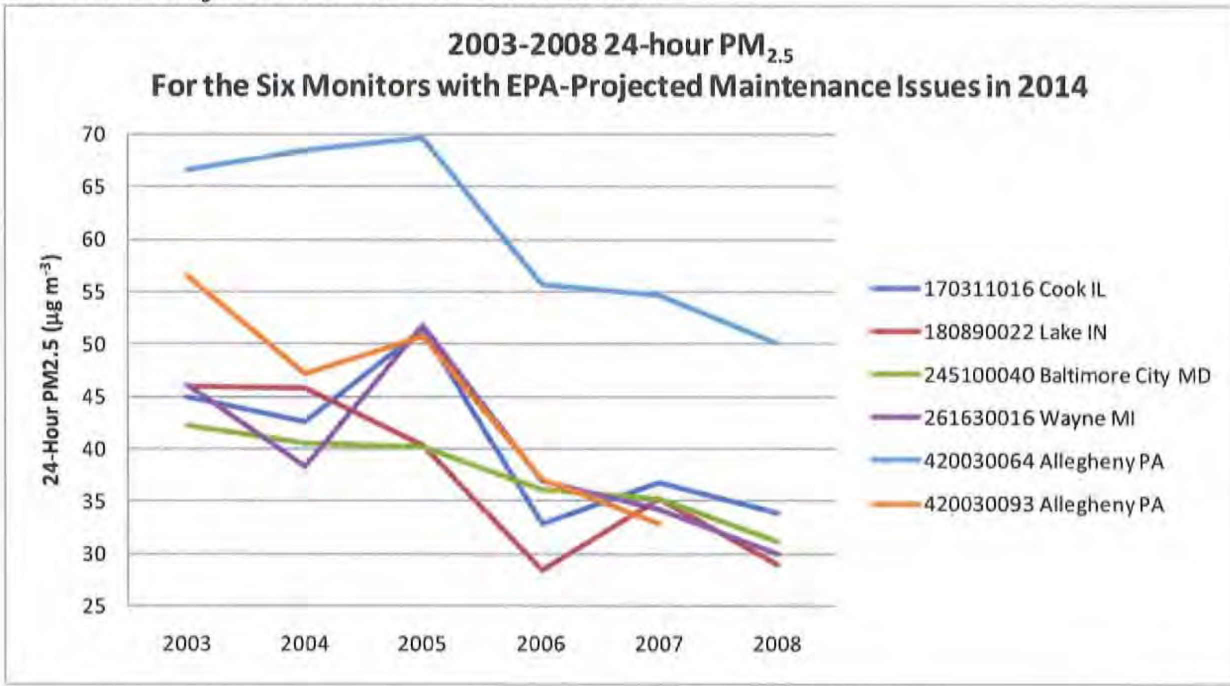
[35] 75 Federal Register 45247, 45249, 45252 (August 2, 2010).

[36] EPA's Trends Report at 1-2.

[37] Although the three base periods used by EPA were 2003-2005, 2004-2006, and 2005-2007, 75 Fed. Reg. at 45247/2, 45249/2, 45252/2, this plot includes data not only for those years but, for additional context, 2008 as well.

[38] The spreadsheet contains design values from 1999-2001 through 2006-2008. *See* http://www.epa.gov/oaqps001/airtrends/values.html.

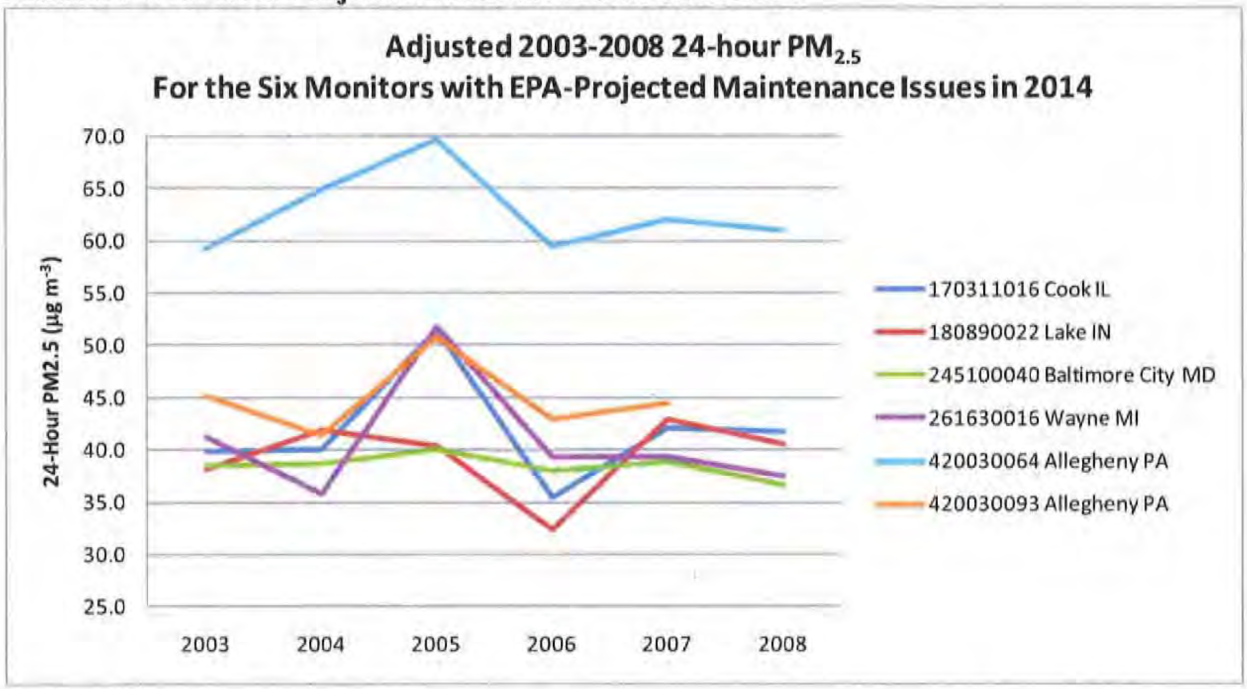
Figure XI-1. Plot of 2003-2008 Annual 98th Percentile 24-hour PM2.5 For Six Monitors With EPA-Projected Maintenance Issues in 2014



It is easy to see that basing a determination of a maintenance problem at any one of these six monitors on the future-year *maximum* $PM_{2.5}$ design value would almost inevitably overstate the air quality design value at that monitor and, based on the strong downward trend in design values, would most likely result in a false determination. There is no reason to believe that the trend that is apparent in the design values at these six monitors is unusual. In fact, a similar trend is likely to exist at most of the downwind monitors evaluated in the proposed rule. It is especially important for EPA to come up with a justifiable methodology for determining maintenance issues since EPA has placed the burden in its significant contribution analysis upon all sites eliminating any and all maintenance issues. Therefore, EPA should revisit its method for identifying downwind maintenance problems, justify its reasoning for choosing a particular method and revise its analysis to make it more representative of current and likely future air quality and to take account of the downward trend in design values.

A more reasonable approach that EPA could have taken to determine maintenance is to, first; remove the trend in the data where air quality is improving over the five-year period, prior to determining the maximum 3-year design value. Briefly, this method would first determine the linear fit to the 5-year (2003-2007) air quality data, calculate the residual values from the difference between the linear fit and the observed values, and then add the residuals to the average of all five years of data (2003-2007 values). The result is an adjusted five year time series with no trend, but has the same average and the same five-year weighted mean design value as the original observations. The result would still capture the inter-annual variability in air quality at sites with improving air quality without biasing the result high for areas where emissions reductions are already resulting in air quality improvement, and would better identify sites where maintenance may be an issue. The plot in figure XI-2 below shows the effect of applying this methodology to the data at the six monitors shown in the previous plot.[39]

Figure XI-2. Plot of Adjusted 2003-2008 Annual 98th Percentile 24-hour PM2.5 For Six Monitors With EPA-Projected Maintenance Issues in 2014



As can be seen, the downward slope at all of these sites has been removed, but the inter-annual variability remains. Table XI-4 below shows the estimated effect of applying this methodology to the projected 2012 base case Design Values for these six sites. These results are a more reasonable estimate of the threshold that may be necessary to maintain attaining air quality in that it eliminates an inadvertent penalty for having made real improvements in air quality through emissions reductions. Furthermore, it leaves a better estimate of inter-annual variability that would be due to inter-annual meteorological and/or emissions variability.

[39] 2008 values are included for context and were not used for adjusting the data.

Table XI-4. 2012 Projected and Adjusted 5-Year Weighted Mean and 3-Year Maximum Design Values For Six Monitors With EPA-Projected Maintenance Problems

			2012 Projected Values			
			5-Year (EPA Method)		5-Year Adjusted (Trend Removed)	
Receptor Monitor ID	Receptor County	Receptor State	Wtd Mean DV	Max DV	Wtd Mean DV	Max DV
170311016	Cook	IL	41.0	44.1	41.0	41.6
180890022	Lake	IN	37.3	42.1	37.3	38.4
245100040	Baltimore City	MD	36.3	38.3	36.3	36.6
261630016	Wayne	MI	40.6	43.0	40.6	41.2
420030064	Allegheny	PA	58.8	62.3	58.8	59.0
420030093	Allegheny	PA	41.1	46.2	41.1	41.3

H. EPA Made a Number of Arbitrary Decisions and Unjustified Assumptions in Their Methodology for Determining Significant Contribution that Result in Unnecessarily Stringent SO_2 Emissions Budgets

The methodology EPA uses to determine which states significantly contribute to nonattainment or interfere with maintenance is described previously in these comments. This section describes how the methodology and assumptions EPA makes in its significant contribution analysis (SCA) result in an overly and unnecessarily stringent SO_2 emissions budget for the states of Georgia, Florida, and Alabama.

In preparing to conduct the SCA, EPA developed emissions reduction cost curves by using IPM to project SO_2 and NO_x emissions in 2012 and 2014 at varying cost per ton increments, ranging from $0 (base case) to $2400 per ton for SO_2 and $0 to $2500 per ton for NO_x. Based on the projected future design values and source apportionment results of the 2012 base case CAMx modeling using 2012 base case emissions, the states of Georgia, Florida and Alabama were determined to significantly contribute to downwind monitors with nonattainment and maintenance issues, making them subject to inclusion in the Transport Rule, at least as Group 2 states. EPA's further analysis using the AQAT to evaluate changes in air quality associated with potential emissions reductions found that in 2014 six monitors would require emissions reductions at significantly higher dollars per ton of SO_2 from upwind states to resolve their 24-hour $PM_{2.5}$ nonattainment and maintenance issues. See Section XI-A for discussion of significant contribution analysis. The states that were determined to contribute above the 1% threshold to these six monitors in the 2012 base case were then designated Group 1 states and will be limited to statewide emissions budgets in 2014 that are approximately equivalent to the statewide emissions projected in the 2014 $2000/ton IPM model run. Since Georgia contributed above the 1% threshold to one of those monitors (Baltimore City, MD) in the 2012 base case, the state was classified as Group 1.

Following is a list of issues demonstrating that the Transport Rule has no basis for requiring a) Georgia to make reductions beyond those that are required by state rule by 2014 and b) Florida and Alabama to make reductions beyond $100 and $200 per ton, respectively, in 2012:

1. EPA Made Significant Errors in the Base Case Emissions Inventory

As discussed previously, EPA attempted to remove the existence of CAIR from the base case emissions. This is not a correct assumption, because in the absence of a final Transport Rule, emission reductions from CAIR and state rules will continue. Thus, even if the Transport Rule were not promulgated in 2012, CAIR would remain in place. In removing CAIR from the base case, EPA made numerous unreasonable assumptions. For Georgia, in particular, the IPM modeling projects unreasonably high SO_2 emissions from several coal units in the 2012 base case.

IPM projects 2012 base case emissions for seven Georgia Power units to be nearly three times their historical emissions (See table below). The over-projection by IPM is so large that it is equivalent to the entire 2012 Transport Rule budget for Georgia. Using our replicated version of the AQAT, we found if EPA used appropriate emissions for Georgia in the 2012 base case, Georgia would not be linked to the Baltimore City, MD, monitor and would, therefore, not be classified as a Group 1 state. Furthermore, as is documented in Section X of these comments and in comments submitted by others, including UARG and the FCG, IPM made erroneous 2012 emissions projections for a number of other states as well. EPA should re-run the CAMx model for the 2012 base case with appropriately corrected emissions to determine the corrected air quality contributions for each state to each appropriate (i.e., after considering monitored AND modeled attainment status) downwind monitor in 2012.

Table XI-5. Historical (2005-2009) and Projected (IPM 2012 Base Case) SO2 Emissions (TPY) For Seven Georgia Power Coal-Fired Units

Unit ID	Historical SO2 Emissions (TPY)*					2012 Base Case IPM Modeling SO2 (TPY)	2012 Limited Trading IPM Modeling SO2 (TPY)
	2005	2006	2007	2008	2009		
Harllee Branch 1	15,979	14,663	17,708	14,878	9,256	41,368	9,963
Harllee Branch 2	16,755	20,355	19,404	19,453	11,259	50,301	12,114
Harllee Branch 3	28,372	33,670	28,423	31,566	16,023	76,945	18,530
Harllee Branch 4	29,407	27,301	32,828	28,085	23,573	77,718	18,716
Jack McDonough MB1	13,842	13,966	13,983	11,653	7,471	40,761	9,816
Jack McDonough MB2	13,829	14,868	14,555	12,672	8,446	40,720	9,806
Mitchell (GA) 3	7,804	5,150	4,919	4,728	223	27,031	5,686
Total	125,990	129,974	131,820	123,035	76,250	354,845	84,632

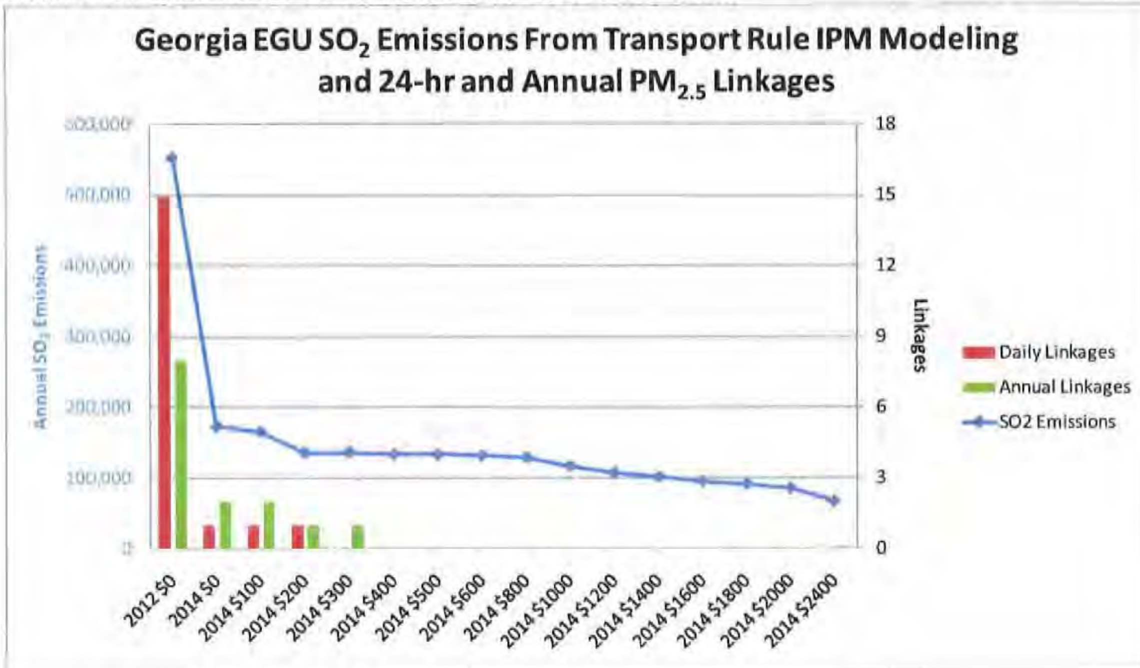
(*Emissions and heat input data obtained from CAMD Data and Maps website: http://camddataandmaps.epa.gov/gdm/index.cfm)

2. EPA's Methodology Did Not Adequately Consider Emissions Reductions That Are Required By Other Rules

Because of flaws in the 2012 base case that have been discussed in previous sections, EPA should not have used those emissions in their current form for determining which states are included in the Transport Rule. The state of Georgia, in an effort to address transport issues, local nonattainment issues, and hazardous air pollutants, developed its own Multi-pollutant Rule. The Multipollutant rule requires the installation of specific control technologies at all of the larger coal-fired power plants in the state. As a result, Georgia Power is in the midst of a massive construction program installing NOx and SO2 controls on many of its coal-fired units. By 2012, over 50 % of the coal generation operated by Georgia Power will be scrubbed. By 2014 that number will grow to over 70% and by 2015 nearly 90% of Georgia Power's coal generation will be scrubbed. These emissions controls are reflected in the 2014 IPM modeling for the Transport Rule (see Figure XI-3 below). The 2012 $0 per ton emissions used for the significant contribution test were extremely high. Had EPA evaluated the contribution from Georgia to downwind nonattainment and maintenance monitors in 2014 at $0 per ton of SO_2, they would have found that Georgia was not linked to nonattainment or maintenance issues at the Baltimore City, MD, monitor. In fact, the only monitors that Georgia is linked to at $0 per ton in 2014 are the two Birmingham monitors, both of which are impacted by local sources. Birmingham has demonstrated monitored attainment for the daily standard and is projected to achieve attainment of the annual standard by 2012 in the Birmingham $PM_{2.5}$ SIP through reductions achieved by the local sources and CAIR.

The graph below also shows that even if local controls are not considered, Georgia resolves all of its linkages at $300 - $400 per ton in 2014. This result should have left Georgia with a projected 2014 SO2 budget of 133,563 tons per year. Furthermore, if local emission controls are appropriately considered early in the methodology, Georgia would have a projected budget in 2014 of no less than 173,257 tons per year. However, Georgia's budget in the proposed Transport Rule is 85,717 tons per year – less than half of what is necessary to resolve all of Georgia's downwind linkages to nonattainment and maintenance issues.

Figure XI-3. Plot Showing EGU SO2 Emissions at 2012 $0 Per Ton and $0 to $2400 Per Ton in 2014 for the State of Georgia, Along With the Number of Downwind Linkages At Each Cost Increment For Annual and 24-Hour PM2.5



3. EPA's Methodology For Determining Maintenance Design Values Leads to Unnecessary Emissions Reduction Requirements

One of the six monitors that required larger upwind emission reductions to have their 24-Hour $PM_{2.5}$ nonattainment and maintenance issues resolved was monitor number 245100040 in Baltimore City, Maryland. Out of the six, this was the one monitor that the state of Georgia was projected to contribute significantly to in the 2012 base case and was, therefore, the basis for Georgia's classification as a Group 1 state. In Figure XI-1 six years of annual 98^{th} percentile daily $PM_{2.5}$ values have been plotted for this monitor, among others. The plot shows a clear, steady downward trend in the data. As discussed in Section XI-G, EPA's proposed Transport Rule approach of using the maximum 3-year design value from the 2003-2007 period for calculating "maintenance" design values in the proposed Transport Rule is unjustified. Had EPA used a justified methodology, such as the approach we proposed in Section XI-G that eliminates a penalty where early emissions reductions are already contributing to improved air quality, EPA should have found that the nonattainment and maintenance issues at the Baltimore City, Maryland, monitor will be resolved in 2014 at $0 per ton; therefore, Georgia should have been determined to have achieved the requirements for the "off ramp" and should be classified as a Group 2 state.

4. If EPA Deems It Necessary To Require 2012 Emissions Reductions Beyond CAIR, It Should Have Analyzed Air Quality Benefits Using the 2012 Emission Reduction Cost Curves

Once EPA established that nonattainment and maintenance could be achieved at all monitors in 2014 at $2000 per ton, it then considered what reductions could be achieved by 2012. EPA concluded that "it is important to require all such reductions by 2012 to ensure that they are achieved as expeditiously as practicable."[40] CAIR was left in place by the Court and is achieving significant emissions reductions and air quality improvements (see Section XI-A). If EPA considered 2012 an important target date to achieve reductions beyond CAIR, it should have conducted an air quality analysis of air quality benefits that could be achieved by 2012 using the 2012 cost curves that were published in the Transport Rule.[41] Using our replicated version of the AQAT, we found that, in 2012, Florida would have resolved all of its downwind $PM_{2.5}$ linkages at $100 per ton, and Alabama would have resolved all of its downwind $PM_{2.5}$ linkages at $200 per ton. This should have resulted in 2012 projected EGU budgets for these two states of 204,309 and 274,958 tons of SO_2, respectively. The proposed remedy budgets are 161,739 and 161,871 tons of SO_2 in 2012, which are overly and unnecessarily stringent to resolve the nonattainment and maintenance issues at the downwind receptors to which these two states are linked.

I. EPA Should Not Move Florida from a Group 2 SO2 State to a Group 1 SO2 State

For the annual $PM_{2.5}$ standard, EPA's use of the air quality assessment tool projected that, after implementation of the proposed FIPs, the Birmingham, Alabama, annual $PM_{2.5}$ monitors would not have a NAAQS air quality nonattainment or maintenance problem. However, the results of the refined air quality modeling, using the regional air quality model CAMx, projected that Birmingham, AL, would exceed the threshold for ''maintenance'' by a slight amount (less than 0.1 $\mu g/m^{-3}$).[42] Based on these results of the refined modeling, EPA has requested comment on whether Florida should be moved from Group 2 to Group 1. We agree with EPA's conclusion that upwind reductions beyond those in the proposed FIPs are not required to address significant contribution and interference with maintenance of the annual $PM_{2.5}$ NAAQS in Birmingham, AL. As EPA states, "the refined air quality modeling projects that Birmingham, AL, will exceed the maintenance criteria by only an extremely slight amount."

In fact, the refined modeling for the Birmingham $PM_{2.5}$ SIP, which was conducted by the Alabama Department of Environmental Management in accordance with EPA guidance on $PM_{2.5}$ attainment modeling and includes local emissions reductions that EPA failed to consider in the refined Transport Rule modeling,[43] shows that the Birmingham area will actually attain the annual $PM_{2.5}$ standard in 2012. Indeed, current air quality is showing that Birmingham is already close to having attaining air quality (i.e., 2007-2009 DV of 15.1 $\mu g\ m^{-3}$). In addition, the significant contribution assessment conducted for the Transport Rule shows that Florida only

[40] 75 Federal Register, 45281 (August 2, 2010).
[41] Significant Contribution Analysis TSD, Tables 1-1 through 1-6.
[42] 75 Federal Register, 45283 (August 2, 2010).
[43] TR Emissions Inventory TSD, p11.

contributes 0.1519 μg m^{-3} to the nonattaining Birmingham monitor in the 2012 base case, a concentration increment which is only 0.0019 μg m^{-3} above the significant contribution threshold of 0.15 μg m^{-3}.

Furthermore, EPA erred in assuming that units 4, 5, 6 and 7 at Plant Crist in Escambia County, Florida, and units 4 and 5 at Plant Crystal River in Citrus County, Florida, have dispatchable wet FGDs that would not operate in the 2012 base case. In fact, the operation of these wet FGDs are required by the state of Florida (see construction permits No. 0330045-023-AC (Crist) (Attachment C) and No. 0170004-019-AC (Crystal River), both of which are being incorporated in their Title V permits) and would reduce the total combined Florida EGU (> 25 MW) SO_2 emissions by almost 40% from the 2012 base case. Had EPA properly accounted for a) the reduction in local emissions in the Birmingham area and b) emissions reductions from Florida sources in the base case, that analysis would almost certainly have found that Florida did not interfere with maintenance of the annual $PM_{2.5}$ standard in Birmingham, AL. Therefore, Florida should not be considered for inclusion as a Group 1 state.

XII. EPA Should Not Have Included Annual NOx Emissions Reductions as Part of the Remedy for $PM_{2.5}$

A. If EPA Had Considered SO2 Emissions First, It Would Have Shown Additional NOx Emission Reductions to Provide Little Benefit

In one of the steps in its methodology for determining significant contribution, EPA assesses NOx emissions first, and then subsequently argues that since SO2 is more effective, no further analysis of NOx emissions beyond $500 per ton would be pursued. Had EPA reversed the order of the assessment, it would have seen that adding NOx emissions reductions after first considering SO2 provides essentially no further benefit. In the Tables XII-1 and XII-2 below, we used our replicated version of the AQAT to estimate the benefit of emissions reductions as the number of monitors remaining in nonattainment or having maintenance issues after applying the emissions reductions at the specified cost level. These results illustrate that for both the daily and annual $PM_{2.5}$ standards, there is little to no downwind benefit from requiring NOx emission reductions at the $500 per ton level.

Table XII-1 Number of Monitors Projected to be Nonattainment or Maintenance for the Daily PM2.5 Standard At \$0 to \$400 Per Ton of SO2 and \$0 and \$500 Per Ton of NOx

NOx First vs. SO2 First - 2014 Daily $PM_{2.5}$			
Daily $PM_{2.5}$ - 2014		Number of Monitors Determined to be	
\$/Ton SO2	\$/Ton NOx	Nonattainment	Maintenance
0	0	40	71
0	500	39	64
100	0	6	16
100	500	5	15
200	0	3	11
200	500	1	9
300	0	1	8
300	500	1	6
400	0	1	7
400	500	1	5

Table XII-2. Number of Monitors Projected to be Nonattainment or Maintenance for the Annual PM2.5 Standard At \$0 to \$400 Per Ton of SO2 and \$0 and \$500 Per Ton of NOx

NOx First vs. SO2 First - 2014 Annual $PM_{2.5}$			
Annual $PM_{2.5}$ - 2014		Number of Monitors Determined to be	
\$/Ton SO2	\$/Ton NOx	Nonattainment	Maintenance
0	0	13	20
0	500	12	19
100	0	3	4
100	500	2	3
200	0	2	3
200	500	2	3
300	0	1	3
300	500	1	3
400	0	1	2
400	500	1	1

The role of NOx in particulate matter formation is further complicated by recent discoveries demonstrating that the production of biogenic secondary organic aerosol (SOA) is heavily influenced by NOx levels.[44] Specifically, this research shows that that biogenic SOA, particularly for isoprene, **is enhanced with lower NOx levels** due to changes in the fate of peroxy radicals. Thus, NOx reductions, particularly in the Southeast which has significant biogenic emissions, could actually result in increased $PM_{2.5}$. Air quality models at present do not include this newly discovered chemistry and, therefore, EPA's analysis does not take into account these potential NOx disbenefits. In addition, the proper simulation of ammonium nitrate and other nitrate aerosol (e.g., organic nitrates) has confounded air quality scientists for many years. As such, the representation of the impacts NOx emission changes in PM levels in these models is incomplete, particularly when attempting to simulate relatively small signals such as interstate contributions to PM.

B. EPA Should Not Regulate Annual NOx Emissions from Southern States

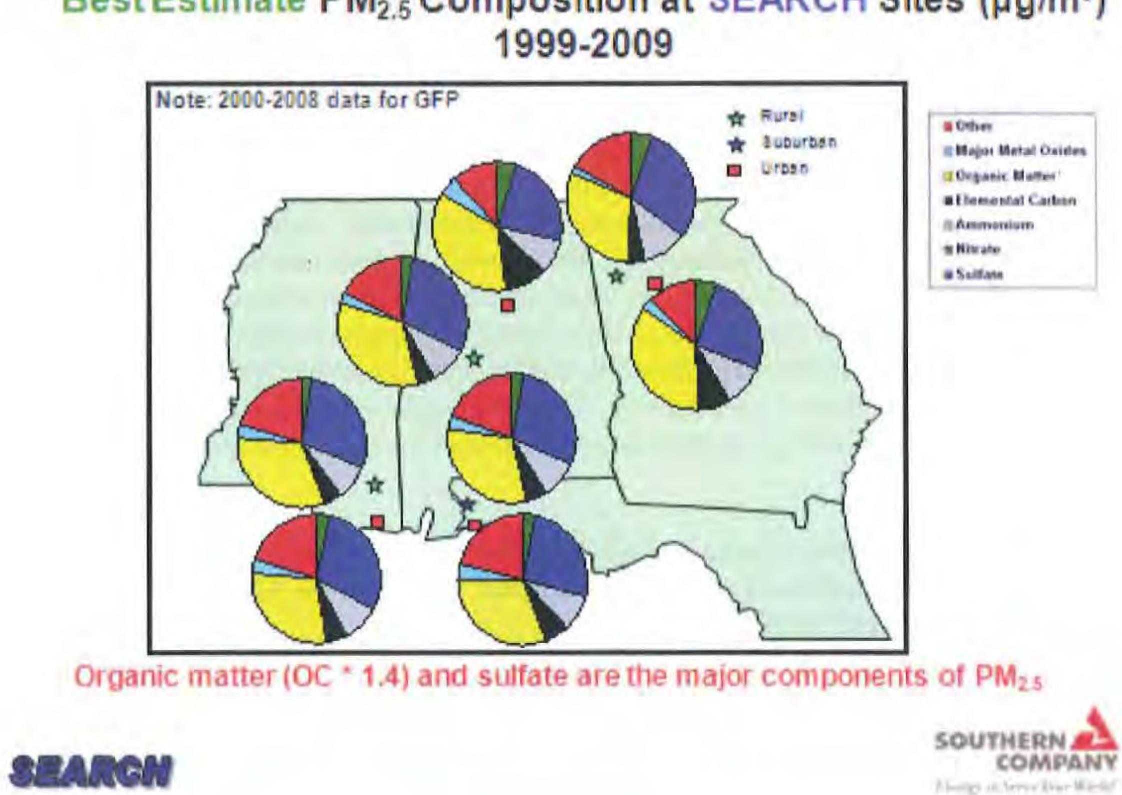
EPA should exclude NOx emissions from the annual program, at least for Southeastern states for a number of reasons:

- It is well known that particulate nitrate represents an exceedingly small fraction (~5%) of $PM_{2.5}$ in the Southeastern US[45] PM mass and speciation data collected at the SEARCH ambient monitoring sites over the last ten years illustrates the composition of $PM\text{-}_{2.5}$ across Georgia, Florida, Alabama and Mississippi and confirm the findings of other studies (see figure XII-3 below).

[44] Surratt, J. D. et al. (2006), Chemical composition of secondary organic aerosol formed from the photooxidation of isoprene., *The journal of physical chemistry. A*, *110*(31), 9665-90, doi:10.1021/jp061734m. ;Ng, N. L. et al. (2007), Effect of NO_x level on secondary organic aerosol (SOA) formation from the photooxidation of terpenes, *Atmospheric Chemistry and Physics Discussions*, *7*(4), 10131-10177, doi:10.5194/acpd-7-10131-2007. ;Hallquist, M. et al. (2009), The formation, properties and impact of secondary organic aerosol: current and emerging issues, *Atmospheric Chemistry and Physics Discussions*, *9*(1), 3555-3762, doi:10.5194/acpd-9-3555-2009. ;Paulot, F. (2009), Unexpected Epoxide Formation in the, *Science*, *730*, doi:10.1126/science.1172910.;Paulot, F., J. D. Crounse, H. G. Kjaergaard, A. Kürten, J. M. St Clair, J. H. Seinfeld, and P. O. Wennberg (2009), Unexpected epoxide formation in the gas-phase photooxidation of isoprene., *Science (New York, N.Y.)*, *325*(5941), 730-3, doi:10.1126/science.1172910. ;Surratt, J. D., A. W. Chan, N. C. Eddingsaas, M. Chan, C. L. Loza, A. J. Kwan, S. P. Hersey, R. C. Flagan, P. O. Wennberg, and J. H. Seinfeld (2010), Reactive intermediates revealed in secondary organic aerosol formation from isoprene., *Proceedings of the National Academy of Sciences of the United States of America*, *107*(15), 6640-5, doi:10.1073/pnas.0911114107. ;Chan, M. N. et al. (2010), Characterization and quantification of isoprene-derived epoxydiols in ambient aerosol in the southeastern United States., *Environmental science & technology*, *44*(12), 4590-6, doi:10.1021/es100596b.

[45] V. Rao, N. Frank, A. Rush & F. Dimmick, Chemical Speciation of PM-2.5 in Urban and Rural Areas, published in National Air Quality and Emissions Trends Report, 2003 Special Studies Edition, US EPA, September 2003 at S19-S23; The Particle Pollution Report: Current Understanding of Air Quality and Emissions through 2003, US EPA, December 2004 at 3; Our Nation's Air: Status and Trends Through 2008, US EPA, February 2010 at 24; see also Clean Air Fine Particle Implementation Rule; Final Rule, 72 Fed. Reg. 20586 at 20,589 - 20594 (Apr. 25, 2007).

Figure XII-1. PM2.5 Composition at the Eight SEARCH Monitoring Sites for the Period 1999-2009



- Several studies have documented that changes in particulate nitrate in the Southeastern US are limited by available ammonia (e.g., Blanchard and Hidy, ISSN 1047-3289 J. Air & Waste Manage. Assoc. 53:283–290; Blanchard et. Al, ISSN:1047-3289 J. Air & Waste Manage. Assoc. 57:1337–1350), Much of the ammonia required to convert NOx reaction products to ammonium nitrate ($PM_{2.5}$) is taken up by SO2 and sulfates in the atmosphere, effectively limiting the role of NOx and nitrates in the formation of $PM_{2.5}$ in the Southeast. Thus the response of ambient $PM_{2.5}$ levels to NOx reductions is very limited ($< \sim 0.5 \mu g/m^3$), even in the face of large SO2 reductions.

- EPA's own results from the modeling supporting the Transport Rule show exceedingly small benefits from NOx reductions (in stark contrast to EPA's assertion that "these [southeastern] states can impact downwind states in cooler climates," not only in the Southeast but also in terms of contributions to monitors in the north, from NOx emissions from Southeast states.[46] The state contributions to downwind monitors calculated from the CAMx source apportionment modeling were provided in the technical information

[46] 75 Federal Register, 45237 (August 2, 2010)

posted on EPA's website. Below is table XIII-3 summarizing the maximum base case contributions to projected downwind nonattainment and maintenance monitors. Maximum values are shown for all downwind nonattainment and maintenance monitors and for only those to which each state is linked. For the linked monitors, the table also shows the nitrate fraction of total sulfate-plus-nitrate from anthropogenic sources, and the maximum nitrate contribution relative to the respective annual and 24-hr $PM_{2.5}$ standards. The maximum statewide contribution from nitrate to any downwind nonattainment or maintenance monitor is 0.0193 $\mu g/m^3$ from Alabama for the annual standard and 0.0364 $\mu g/m^3$ from Georgia for the 24-hr standard. The maximum statewide contribution to a linked downwind nonattainment or maintenance monitor is 0.0193 $\mu g/m^3$ (0.13% of the standard) from Alabama for the annual standard and 0.0332 $\mu g/m^3$ (0.10% of the standard) from Georgia for the 24-hr standard. The maximum contributions from nitrate to linked monitors for these four states is approximately one tenth or less of the significant contribution threshold, and is generally much less than one tenth of the total sulfate-plus-nitrate contribution. Thus, statewide reductions in sulfate will be at least ten times more effective at eliminating downwind contributions than the same relative nitrate reductions.

Table XII-3. Statewide Contributions of Nitrate to Projected Baseline Maintenance and Nonattainment Receptors From the Transport Rule Source Apportionment Modeling For Alabama, Florida, Georgia and Mississippi

	Annual $PM_{2.5}$				24-Hr $PM_{2.5}$			
		Linked Receptors Only				Linked Receptors Only		
State	Largest Contribution to Any NA or Maint Receptor	Largest Contribution to "Linked" NA or Maint Receptor	NO3 Fraction of SO4 plus NO3 Contribution	NO3 Fraction of Standard	Largest Contribution to Any NA or Maint Receptor	Largest Contribution to "Linked" NA or Maint Receptor	NO3 Fraction of SO4 plus NO3 Contribution	NO3 Fraction of Standard
AL	0.0193	0.0193	4.13%	0.13%	0.0193	0.0078	7.19%	0.02%
FL	0.0031	0.0030	1.65%	0.02%	0.0116	**	**	**
GA	0.0159	0.0159	2.57%	0.11%	0.0364	0.0332	9.45%	0.10%
MS	0.0067	*	*	*	0.0114	*	*	*

*Mississippi is not linked to any nonattainment or maintenance receptors for annual or 24-hr $PM_{2.5}$
**Florida is not linked to any nonattainment or maintenance receptors for 24-hour $PM_{2.5}$

C. EPA Should Not Regulate Annual NOx Emissions from Northern States for $PM_{2.5}$

Although particulate nitrate can be an important fraction of $PM_{2.5}$ during the winter in the northern states, EPA should not have included it in its remedy for several reasons:

- EPA chose not to include ammonia emissions in this transport rule. The formation of particulate nitrate is an inherently non-linear process, is strongly thermodynamically driven, and is strongly associated with available ammonia. In fact, particulate nitrate is often driven by available ammonia, regardless of available nitric acid. Several studies have shown the effectiveness of ammonia emissions reductions over NOx reductions in reducing particulate nitrate in the Midwest.[47] By excluding ammonia from consideration, EPA could not properly assess the role of NOx versus ammonia, especially using the linear assumptions in AQAT.

- As demonstrated above, NOx reductions provide little additional benefits if SO2 controls are applied first.

- As stated above, lower NOx can increase SOA production thus there is a potential NOx disbenefit that EPAs methodology is incapable of assessing.

For all the reasons described above, EPA should not include NOx in the remedy for $PM_{2.5}$.

XIII. EPA's State Budget and Unit Allocation Methodologies Are Fundamentally Flawed

To establish state budgets and unit allocations, EPA used a combination of reported data and projected data, both adjusted for controls. As mentioned earlier, EPA's methodology was not clearly defined and Southern Company spent countless hours replicating EPA's approach. However, Southern Company has identified a number of fundamental flaws in EPA's methodologies for developing and adjusting this data for purposes of setting the state budgets and unit allocations. These flaws are described below.

A. 2009 Was Not an "Average Year"

To develop the reported emissions data for purposes of setting state budgets and unit allocations EPA took the most recent "non-null" quarterly data (through the third quarter of 2009) for each quarter (quarter one through four). In most cases, this meant using data from the fourth quarter of 2008 through the third quarter of 2009 as a representative year (or 2009 ozone season data as a representative ozone season). This process is significantly flawed. EPA repeatedly claims that state budgets are based on emissions from an "average year." Yet its methods accomplish nothing of the sort. Put simply, EPA's selected representative year is anything but average.

From 2008 through 2009, the nation was in the middle of the most significant economic downturn since the great depression. Electricity demand and heat input were unusually low. EPA appears to recognize this anomaly by adjusting reported NOx data based on 2008 heat input.[48] But even that adjustment does not fully account for the unusually low demand for electricity beginning in the second half of 2008. In addition, in 2009 natural gas prices were at extraordinarily low resulting in highly unusual dispatch of the fossil fuel fired electric generating fleet. In some cases, large coal-fired units were idled while natural gas fired units – normally reserved for peaking power – ran at much higher capacity factors. Due to the combined forces of (i) decreased demand and (ii) low natural gas prices, 2009 is perhaps the least representative year

[47] Asifs, Ansari and Spyros N. Pandis, Environ. Sci. Technol. 1998, 32, 2706-2714; Tsimpidi, et. al, ISSN:1047-3289 J. Air & Waste Manage. Assoc. 57:1489–1498 DOI:10.3155/1047-3289.57.12.1489; ISSN:1047-3289 *J. Air & Waste Manage. Assoc.* **58**:1463–1473 DOI:10.3155/1047-3289.58.11.1463; Pinder, R. W., et al, Environ. Sci. Technol. **2007**, 41, 380-386

[48] As explained in the UARG comments, EPA must explain why a similar adjustment for the economic downturn was not made with respect to the SO2 budgets and allocations.

in decades for determining average annual emissions. EPA should fully account for the economic downturn by selecting reporting years that were not impacted by the economic downturn.

Instead of attempting to select a single representative year, consistent with past practice, EPA should use a longer average period of time to develop reported emissions data. By selecting a longer period of time (e.g., three years as used in the Acid Rain Program, the NOx SIP Call and CAIR), EPA would capture data that is more representative. Selecting the three year period from 2005 to 2007 would fully account for the economic downturn, capture two full operational cycles for a typical unit, and would provide much more reliable data.

B. EPA's "Adjustments" Are Flawed and Inconsistently Applied

EPA "adjusts" both reported and projected data in the process of setting state budgets and unit allocations. Based on our review in the time EPA has allowed, we have uncovered flaws in the methodologies, examples of where the stated methodologies appear not to have been applied, and situations were EPA adjusts similar data differently. Some examples include:

- ***Gadsden 2 (methodology misapplied/unclear).*** EPA does not appear to have applied its prescribed methodology when setting Gadsden 2's SO2 allocation. It appears that a unique adjustment was made to the Heat Input for Gadsden 2, but it is very difficult to determine EPA's methodology.

- ***Bowen 2 (flawed methodology).*** Bowen 2 experienced a prolonged outage in the first quarter of 2009 to install FGD controls. Under EPA's stated methodology for adjusting reported data for controls installed during the reporting period EPA essentially ends up using data from only the third quarter in 2009 to set Bowen 2's annual SO2 allocation.[49] Using limited operating time to establish a long-term average emission rate is inadequate and may be unrepresentative. In this case, the flawed methodology results in the Bowen 2 adjusted projected emission rate and 2012 SO2 allocations to be much lower than the other, similar units at the same site.

- ***Bowen 1 (inconsistent application of methodology).*** Bowen 1 experienced a regularly planned outage in approximately half of the fourth quarter 2008. Accordingly, its heat input and NOx and SO2 emissions for that quarter were half of what they would be in a typical quarter. Yet EPA used this quarterly data to set Georgia's state budget and Bowen 1's allocations. To be consistent of its treatment of other units, EPA should use heat input and emissions data from the fourth quarter 2007 in place of the unrepresentative data reported in the fourth quarter of 2008.[50]

C. EPA Should Allow States To Develop Allocations

EPA should allow states to develop state-specific allocations through the SIP process. States were very successful in dividing allocations for CAIR and the NOx SIP Call and are better suited to developing fair and consistent allocations that take into consideration unique aspects of EGUs

[49] The Bowen 2 FGD actually started up just before the start of the second quarter of 2009. It appears that EPA assumed that only data from the third quarter of 2009 represented operation post FGD control.
[50] State Budgets, Unit Allocations, and Unit Emissions Rates TSD, page 9.

(e.g., fuel mixes or anticipated new unit construction) in the state. States are most familiar with the types of EGUs in their states and can best determine how allocations should be made.

D. EPA Should Reward, Not Penalize, Units for Early Reductions

EPA's methodology for distributing allocations based on unit-by-unit analysis unfairly penalizes sources that installed controls before 2010 (e.g., Miller 3 & 4 FGD, Miller 1, 2, 3 & 4 SCR, Gorgas 8, 9, and 10 FGD, Gorgas 10 SCR, Gaston 5 SCR). Allowances should be allocated to sources based on a universal methodology. Additionally sources that have been burning low sulfur coals, establishing a lower base of SO2 emissions will be unfairly penalized under the current allocation methodology. Unfairly distributing allocations negates the value of a market-based program.

XIV. EPA Should Adopt an Interstate Trading Program and Abandon the Alternatives Offered for Comment

EPA's proposed limited interstate trading option provides a limited amount of flexibility and allows more cost-effective compliance options. EPA has historically allowed interstate trading in transport rules and should do so in this case. The intrastate trading option (Alternative 1) is completely unworkable and cumbersome. And EPA has no authority for the direct control option (Alternative 2), which provides for little to no flexibility. As stated, Southern Company strongly supports a flexible interstate trading program. Although EPA's interstate trading option is preferable to either of the two proposed alternatives, as explained in Section V, EPA should evaluate whether less stringent limits on trading can be adopted without compromising the anticipated air quality benefits of the Transport Rule.

A. The Intrastate Trading Alternative Is Unworkable, Cumbersome and Far Inferior to EPA's Proposed Remedy

Southern Company agrees with EPA that the State Budgets/Intrastate Trading option is more problematic and costly than the preferred option. As noted, this option would be more resource intensive, more complex, and less flexible than the other two options.[51] Southern Company can hardly fathom the waste of federal, state and industry resources and the administrative burden if there were 82 allowance trading programs. Such limited allowance markets would provide very little of the flexibility that trading is designed to create, and would involve orders of magnitude more resources to implement. In addition to this alternative's lack of benefits and excessive burdens, it does not make sense given the regional analysis EPA applied for some of the rule's most significant determinations. For example, the proposed rule uses regional analysis to determine that the required reductions should come from the electric power sector and, in a limited way, to determine cost effectiveness, despite the fact that some states may have more cost effective control options from other sectors.

Under this proposed alternative, it is all the more critical that EPA allow states the flexibility to determine how best to achieve any required reductions. As articulated in the proposed rule, under this alternative, EPA would identify linkages based on total anthropogenic emissions and then hamstring the states by imposing a FIP that requires all needed reductions to come from

[51] 75 Federal Resister, 45330 (August 2, 2010)

EGUs. If EPA were tempted to limit trading to state boundaries, there is absolutely no justification for further limiting where those reductions must be derived. As noted above, how reductions are achieved is the primary responsibility of the state. Absent the flexibility interstate trading allows, there is little to no basis for proscribing over 80 complex intrastate trading programs that are essentially identical for all states.

In addition to the extraordinary administrative burden associated with 82 allowance trading programs that may be required under this option, EPA proposes to run numerous auctions. Southern Company fundamentally disagrees that such auctions are necessary to avoid the exercise of market power. More basically, however, Southern Company is certain that the modicum of benefit associated with such a restricted trading program is underwhelming in the face of the extraordinary administrative burden needed to implement this alternative.

B. EPA Cannot and Should Not Adopt the Direct Control Alternative

Under this alternative for addressing interstate transport, EPA would simply mandate unit-specific emission limits for the units in the affected states.[52] However, it is well-established that under Section 110 of the Act Congress reserved for the states the authority to decide which sources to control and to what extent.[53]

Even if EPA had authority to mandate unit-specific limits under Section 110 of the Act, unit-specific reductions could not be achieved within the timeframes provided by the rule for the many reasons outlined in Sections VI and VII above. Furthermore, EPA's Regulatory Impact Analysis confirms that the cost of any reductions that could be achieved would be significantly higher than EPA's preferred limited trading option. These are costs that in most instances would be borne by our customers at a time when they can least afford it – just as they are trying to recover from the worst recession in our nation's history. For all of these reasons, Southern Company urges EPA to reject the direct control alternative.

XV. EPA Should Encourage – Not Discourage – Fossil to Biomass Conversions

Southern Company encourages EPA to reconsider its definition of covered unit and allow for a limited exclusion for biomass facilities. As proposed, the Transport Rule covers any unit greater than 25 MW that burns (or has burned) any amount of fossil fuel since 1990. Under this structure, biomass-fired power plants that burn no fossil fuel are excluded, unless they have burned fossil fuel at some point since 1990. Thus, a facility that converts from fossil fuel to biomass is treated differently than a new biomass facility that has never burned fossil fuel. The former must hold allowances. The latter has no such requirement. There is no rational basis for such a distinction. To the contrary, EPA should encourage conversions from fossil fuels to renewable fuels. Furthermore, the Transport Rule concerns current and future air quality. That a given facility once burned fossil-fuel is wholly irrelevant to current and future air quality. Put simply, for purposes of this rule, there is no difference between a converted biomass facility and

[52] 75 Federal Register, 45330-45331 (August 2, 2010).
[53] Michigan v. EPA, 213 F.3d 663, 686 (D.C. Cir. 2000); Union Electric Co. v. EPA, 427 U.S. 246, 269 (1976); Virginia v. EPA, 108 F.3d 1397, 1408 (D.C. Cir. 1997).

a new greenfield biomass facility, and EPA has no basis for including one and excluding the other.

In addition, in order to promote the development of renewable biomass energy, Southern Company encourages EPA to exclude all biomass facilities that burn less than 10% fossil-fuel. Many biomass facilities use small amounts of fossil fuel to minimize emissions during startup and shutdown. Burning fuel oil or natural gas during these periods helps provide combustion stability and control during startup and shutdown, which can help operators optimize the fire to limit or prevent high emission events. As the fire becomes more stable through the startup process, biomass is introduced until combustion is optimal. EPA should encourage, not discourage, the use of minimal amounts of fossil fuels to reduce emissions. This proposed 10% fossil-fuel exclusion is consistent with New Source Performance Standard methods for categorizing multi-fuel units that burn one primary fuel with a very limited amount of another fuel. EPA should adopt a similar approach in this rule.

XVI. Southern Company Supports Several of EPA's Decisions in the Proposed Transport Rule

As discussed throughout these comments, Southern Company has many concerns with the Proposed Transport Rule. However, we support several of EPA's decisions in the proposed rule including: 1) EPA's decision to allow interstate trading, albeit overly limited, in the preferred approach; as discussed earlier, EPA should consider additional trading flexibility; 2) EPA's decision to allow banking of allowances; 3) EPA's decision to not establish allowance auctions in the preferred approach; 4) EPA's decision to limit the applicability for the Transport Rule to units greater than 25 megawatts; 5) EPA's decision to allow retired units to continue to receive allowances for some time; 6) EPA's decision to retain the current ozone season; and 7) EPA's decision to phase in the assurance provisions.

A. EPA's Decision to Allow Interstate Trading, Although EPA Should Have Allowed More

EPA's Proposed Remedy Option allows limited interstate allowance trading, while its two alternative options would not allow any interstate trading. Southern Company supports EPA's proposal to permit at least some degree of allowance trading, although as discussed elsewhere, EPA should have considered more trading. Permitting interstate allowance trading would provide for increased flexibility and permit more cost-effective compliance options.

B. EPA's Decision to Allow Allowance Banking

The Proposed Transport Rule properly recognizes the important environmental and economic benefits of allowance banking, a feature of CAIR that was not challenged in the litigation on that rule and that the court's opinion in no way undermines. The ability of sources to use banked allowances for compliance with the program encourages them to make early emission reductions to the extent that cost-effective early reductions are possible. Unfortunately, the nature and stringency of the proposed rule's emission reduction requirements and its proposed compliance schedule would make it very difficult for most sources to make extra emission reductions during the early years of the program. Permitting allowance banking in conjunction with an adjustment to the compliance schedule that would allow sources adequate time to comply with the program (and give states adequate time to develop SIPs) could well result in greater amounts of early emission reductions and, most likely, greater emission reductions over the long run.

C. EPA's Decision to Not Establish Allowance Auctions in the Preferred Approach

Southern Company supports EPA's proposal not to include any allowance auctioning under its Proposed Remedy Option. No need or reason exists to use allowance auctions to implement the Proposed Transport Rule's emission reduction requirements. If, however, EPA promulgates a final rule based on the Intrastate Trading Remedy Option, an option that Southern Company does not support, EPA should remove from that option the proposed provisions for allowance auctions. It is entirely possible to accomplish the objectives of those proposed auctions through distribution of allowances free of charge.

D. EPA's Decision to Limit the Applicability to Units Greater Than 25 MW

Southern Company fully supports EPA's proposal to exclude small EGUs of less than 25 MW. Most units this size are used only rarely, for example, as emergency or backup units or during extreme peaks in demand. Accordingly, they are dispatched for short periods of time, primarily for electric reliability reasons. A cap and trade program, which determines compliance over an annual or seasonal basis, is ill-suited for addressing any emission concerns associated with such units. If these smaller units were included in the rule, they would become subject to costly monitoring requirements in addition to the SO2 and NOx compliance obligations. Given the *de minimis* emissions involved, these costs far exceed any potential benefits and thus would not be cost-effective. EPA should retain its consistent practice of excluding these small units. In the unlikely event that EPA breaks from its historical practice, it should only do so after determining on an individual unit (or state-by-state) level that smaller units are linked to actual air quality concerns to an extent that warrants their inclusion in the program and that there are cost-effective means available to address those impacts.

E. EPA's Decision to Allow Retired Units to Continue to Receive Allowances for Some Time

EPA requests comment on its proposal to continue to allocate allowances to non-operating units.[54] We support EPA's proposal to continue allocations to non-operating units but believe that the allocations should be perpetual, as they are under Title IV. Perpetual allocations encourage retirement of less efficient units, and, as EPA notes, discourages operators from continuing to operate older units "simply to avoid losing the allowance allocations for those units."[55] EPA's proposal still promotes continued operation of older less efficient units because each year of operation continues the unit's allocation by an additional year. Further, unit owners will be much more likely to retire units if they have control over the allowances perpetually and could plan on the allocations for both existing and new units or choose to sell the allowances to other entities for their new units. In short, perpetual allocations make planning easier, provides more certainty and best encourages retirement of older units.

[54] 75 Federal Register, 45311 (August 2, 2010).
[55] 75 Federal Register, 45310 (August 2, 2010).

F. EPA's Decision to Retain the Current Ozone Season

Southern Company fully supports EPA's decision to retain the current ozone season (May 1 to September 30). EPA has consistently used this five month period to define the ozone season in prior interstate transport rulemakings – CAIR and the NOx SIP Call. Extending it would represent a significant break from this established approach and would call into question EPA's ozone season analyses underlying this rule, which are all based on a five month ozone season. An extension would therefore require EPA to revise its ozone season analyses and publish a supplemental proposal to address ozone transport.

G. EPA's Decision to Not Begin the Assurance Provisions Before 2014

Although EPA should not begin compliance any sooner than 2015, we support EPA's proposal to phase-in the assurance provisions. Transition from one allowance program to another (e.g., from CAIR to the proposed Transport Rule or from it to a future transport rule) is likely to require significant adjustments in unit operations and system dispatch. Owners and operators need a period of time to adjust to the new requirements without the assurance provisions in place. The assurance provisions only apply where all statewide covered unit emissions exceed the state budget plus variability limits. Since there are multiple owners and operators impacting statewide emissions and all are adjusting their operations to account for the new rule at the same time, it is all the more important that the assurance provisions be phased-in. Put simply, EPA's proposal to phase-in the assurance provisions is an important aspect of its transition policy and should be retained in this proposal and in future transition periods (e.g. from this to the next transport rule).

Southern Company appreciates the opportunity to submit these comments. If you have any questions about these comments, please contact Sarah Markham at 205.257.6780. For questions about Southern Company's "Replicated" AQAT, please contact Justin Walters at 205.257.7558 or jwalters@southernco.com.

Attachment 3.

Southern Company comments on NODA 3

UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY

COMMENTS OF SOUTHERN COMPANY ON EPA'S THIRD NOTICE OF DATA AVAILABILITY SUPPORTING FEDERAL IMPLEMENTAION PLANS TO REDUCE INTERSTATE TRANSPORT OF FINE PARTICULATE MATTER AND OZONE (76 FED. REG. 1109 (JAN. 7, 2011))

DOCKET ID NO. EPA–HQ–OAR–2009–0491

SOUTHERN COMPANY
600 NORTH 18TH STREET
BIRMINGHAM, AL 35203

FEBRUARY 7, 2011

COMMENTS OF SOUTHERN COMPANY
ON
EPA'S THIRD NOTICE OF DATA AVAILABILITY SUPPORTING FEDERAL IMPLEMENTAION PLANS TO REDUCE INTERSTATE TRANSPORT OF FINE PARTICULATE MATTER AND OZONE
(76 FED. REG. 1109 (JAN. 7, 2011))

Southern Company submits the following comments on the Environmental Protection Agency's (EPA) third Notice of Data Availability (hereinafter referred to as NODA3) supporting the proposed Transport Rule, noticed at 76 Fed. Reg. 1109 (Jan. 7, 2011). Additionally, Southern Company is a member of the Utility Air Regulatory Group (UARG) and fully supports UARG's comments.

In the NODA3, EPA requests comment on two new allocation methodologies, an abbreviated State Implementation Plan (SIP) process, as well as issues regarding the assurance provisions in the proposed Transport Rule. However, with the NODA3, EPA has for the third time declined to illustrate how the new information will impact the final Transport Rule. As Southern Company expressed in our comments on the proposed Transport Rule, the first Notice of Data Availability (NODA1), and the second Notice of Data Availability (NODA2) it is extremely difficult to provide meaningful comments on new information without understanding how it will impact the final Transport Rule. EPA continues to ask stakeholders to comment on various changes to the proposed Transport Rule in isolation. It is imperative that EPA not piecemeal the public comment process and that the public be afforded the opportunity to comment on a single comprehensive, comprehendible regulatory proposal. Therefore, EPA must issue a supplemental proposed rule, one that incorporates all the "corrected" updated data and reapplies a "corrected" methodology, with an adequate time for public comment. A more thorough explanation and additional concerns with the NODA3 are identified below.

Table of Contents

I. EPA Must Issue a Supplemental Notice of Proposed Rulemaking

As explained in Southern Company's comments on the proposed Transport Rule, the first Notice of Data Availability (NODA1), and the second Notice of Data Availability (NODA2), it is extremely difficult to comment on a "moving" target. The NODA3 represents the third time since EPA proposed the Transport Rule in August 2010, that EPA has issued new data or ideas without illustrating how it will impact the final rule. By the date of EPA's third Notice of Data Availability, EPA has proposed: (i) three different remedies; (ii) two different IPM versions; (iii) three different fuel cost assumptions; (iv) revised emissions inventories; and now (v) three different unit level allocation methods. EPA has essentially asked for comment on numerous isolated ideas and sets of data—not a comprehensive and comprehendible remedy under Section 110(a)(2)(D). Not only does EPA's patch-work approach make it difficult to comment, but it also makes it impossible to plan for compliance. EPA proposes the Transport Rule compliance period will begin in January 2012, a mere six months after the anticipated issuance of the final rule. With only ten months to go before the proposed rule compliance date, utilities do not know which state is "in" for each program, the state budgets, or the individual unit-level allocations. This type of regulatory development process along with the compressed compliance timeline is simply unworkable for affected sources.

In the NODA3, EPA requests comment on two alternative allocation methodologies, both of which are based on the outdated proposed Transport Rule state budgets. EPA already issued new versions of NEEDS and IPM in previous NODAs that would change the overall state budgets, yet has declined to issue any updated state budgets. Without the updated state budgets and subsequent allocations, utilities cannot plan for compliance. Further, the NODA3 asks stakeholders to compare the proposed Transport Rule allocations to two new allocation methodologies. This does not lead to a meaningful comparison since the underlying data and modeling files used to establish the proposed Transport Rule allocations contain numerous errors.[1] Without both the updated state budgets and updated unit-level identifications and allocations from the proposed Transport Rule, we cannot provide a meaningful comparison of the impacts of each option on our generation planning and operations.

Given the magnitude of errors and flawed methodologies identified in Southern Company's previous comments and the magnitude of regulatory uncertainty that still remains, EPA must take the necessary time to:

- correct the errors (in data and assumptions);
- re-run all the models (IPM, CAMx, OSAT, PSAT, AQAT);
- adjust its methodology applied in the significant contribution analysis (as suggested in previous Southern Company comments);
- apply the revised methodology with the corrected data, assumptions, and model outputs;
- update the proposed budgets and allocations; and
- **issue a supplemental proposed rule—with all supporting data, files, and models—allowing adequate time for public review and comment.**

[1] As noted in Southern Company's comments on the NODA1, EPA failed to illustrate how the new data in NODA1 would change the state budgets and unit-level allocations. Further, EPA failed to provide enough information for stakeholders to calculate these themselves.

In the NODA3, EPA notes that "A number of commenters requested that EPA publish allocations and underlying data for any potential alternative allocation methods before issuing a final Transport Rule." (76 Fed. Reg. at 1,110). To the extent EPA is suggesting that the information provided with NODA3 is sufficient information to support a final rule or satisfy Southern Company's request, EPA is mistaken.

II. The Abbreviated SIP Process Does Not Remedy EPA's Unlawful Bypass of the States

As explained more fully in Southern Company's and UARG's comments on the proposed Transport Rule, the Clean Air Act (CAA) does not give EPA the authority to promulgate a FIP before allowing the states to submit a SIP. The opportunity to replace a FIP with a SIP at some point in the future does not satisfy EPA's obligation to provide states an opportunity to craft their own plans at the outset of the program. In the NODA3, EPA proposes an opportunity for states to submit abbreviated allocation SIPs. We support EPA allowing states the opportunity to develop SIPs – as required by the CAA. But the abbreviated SIP concept falls well short of what the CAA requires. Additionally, under the abbreviated SIP process, states would be required to submit proposed allocation SIPs by November 2011 – only a few months after EPA plans to issue the final rule – a virtually impossible task. Even more egregious is the fact that these SIPs would not impact the allocations until 2014, which means that states will be forced to use EPA's FIP allocation scheme in 2012 and 2013.

Southern Company reiterates the point made in the proposed Transport Rule comments, that the 2012 compliance date is unreasonable and unjustified. However, if EPA insists on a near-term compliance date, it must give states an opportunity to develop an allocation scheme, at the outset of the program, that reflects each states own "sensitive . . . choices" on how to implement section 110(a)(2)(D)(i)(I). States are better suited to developing fair and consistent allocations that take into consideration the unique aspects of electric generating units (EGUs) (e.g., fuel mixes or anticipated new unit construction) and economic concerns in the state. The one-size-fits-all scheme of an EPA FIP will unnecessarily penalize many units leaving some with little to no compliance alternatives given the unreasonable proposed deadlines. The CAA envisions allowing regulated sources a reasonable time to implement compliance plans, which EPA is not doing in this rulemaking. At a minimum, EPA should offer several approved model allocation methods, any one of which could be adopted by a state.

In every aspect of responding to any findings in the final rule, states must be afforded ample opportunity to make their "sensitive ... choices" at the outset of the rule. This includes, among other things, broad discretion to determine which units will be covered, where reductions will come from, and how to address new units. For example, states should not be forced to have a new unit set aside; rather they should be afforded the discretion to determine whether, and to what extent, a new unit set aside is warranted.

III. Each of the Proposed Allocation Methodologies Contain Significant Flaws

In the NODA3, EPA proposed two additional unit allocation methodologies for comment and notes that it "will consider these alternative allocation methodologies, as well as the allocation methodologies presented in the proposed Transport Rule." (76 Fed. Reg. at 1,110). In the proposed Transport Rule, EPA allocated to units based on each unit's proportionate share of state-wide emissions (either projected or reported). Both of the new NODA3 allocation methods are based on heat-input. Option 1 is a pure heat-input allocation method and would allocate based on each unit's proportionate share of the state's total historic heat input. Option 2 would yield the same initial allocation pattern as Option 1 (based on historical heat input) but would then add a constraint (i.e., a limit on allocations) based on a unit's reasonably foreseeable maximum emissions under the proposed Transport Rule trading programs. Each of these methods contain significant flaws that must be addressed.

First, as addressed in detail in Southern Company's comments on EPA's proposed Transport Rule, the original proposed Transport Rule allocation methodology is very complicated and difficult to replicate.[2] The proposed Transport Rule allocations were based on either adjusted historical emissions or on adjusted projected emissions. EPA should not rely on projected emissions as a basis for unit allocations. Regional energy planning models (such as the IPM) are ill-suited for accurately projecting individual unit emissions, and using such a model to dole out valuable emission allowances is arbitrary. Allocations should be based on actual emissions. Consistent with past practice (e.g, in the Acid Rain Program, NOx Budget Program, and CAIR), EPA should use a representative range of historical data rather than a single year to determine a unit's proportionate share of emissions.

Second, EPA's pure heat-input based allocation method (i.e., NODA3 Option 1) is arbitrary and leads to absurd results. For example, in this approach, many large natural gas fired units would receive allocations more than 500 times their highest single year of emissions during the seven-year baseline period that EPA evaluates in NODA3. This option provides an overwhelming windfall to natural gas-fired units, and results in significant under–allocation to coal-based generation, with no consideration of allowance needs. Table 1 below illustrates this imbalance for SO2. EPA should not develop a pure heat-input based allocation scheme that does not give any consideration to historical emissions or need.

Table 1. Example of SO2 Allowances Allocations at Various Southern Company Units

	Unit Type	Name Plate Capacity (MW)	Max 2003-2009 Emissions (tons)	Proposed Transport Rule	NODA3 Option 1	NODA3 Option 2
McIntosh CC Unit 10	Combined Cycle	659	8	8	4,715	884
Barry CC Unit 6	Combined Cycle	535	6	7	2,741	783
Bowen Unit 1	Steam Boiler	700	44,181	2,742	10,734	11,695
Crist Unit 4	Steam Boiler	75	3,757	2,752	510	742
Branch Unit 4	Steam Boiler	490	32,828	25,162	6,692	7,291
Miller Unit 4	Steam Boiler	660	15,029	1,607	8,079	9,248

Third, if EPA uses a heat-input based allocation method, it must use an emission constraint that grounds a unit's allocations in reality – using real and credible emissions data. In NODA3 Option 2, EPA attempts to correct the inconceivable over-allocations that result from a straight heat-input

[2] Southern Company spent countless hours trying to replicate EPA's methodology and was unsuccessful for many units.

based method (i.e., Option 1). To do so, EPA essentially caps a unit's allocation at the greater of its "maximum historical baseline emissions" (i.e., highest emissions for each compliance period from 2003 to 2009) and its "well-controlled-rate-maximum" (a calculated value). Option 2 contains hundreds and hundreds of examples of gross under- and over-allocations after applying Option 2's emission constraint. Put simply, EPA's emission constraint failed. The bulk of that failure is due to the flawed "well-controlled-rate-maximum" value.

For a unit that reports hourly heat input, the "well-controlled-rate maximum" equals:

- that unit's maximum hourly heat input,
- multiplied by 0.06 lbs/mmBtu (for both SO2 and NOx allocations),
- multiplied by 8,760 hours (or 3,672 for ozone season),
- multiplied by set-technology-specific capacity factors.

This approach is fundamentally flawed. Option 2 can still lead to allocations that are 200 times greater than a unit's "maximum historical baseline emissions" (see Table 1 above and EPA's NODA3 Allocation Tables in the Docket). Also, there is no basis to use an emission rate (0.06 lbs/mmBtu for both SO2 and NOx) that is admittedly based on a well-controlled *coal* unit for all units. Individual units have significantly different emission rates depending on the fuel used; there is no reason for EPA to ignore such a fact when calculating an emissions value. Further, EPA's use of technology-specific capacity factors does not remedy the flaw. EPA's capacity factors are based on its effort to determine a realistic average capacity for certain technology types. Doing so might lead to a defensible prediction of maximum emissions if a proper fuel- or technology-specific emission rate were used, but given EPA's use of a coal-specific emission rate, the capacity adjustment is wholly ineffective at correcting the error. If EPA proceeds with this allocation methodology, it should throw out the flawed "well-controlled-rate-maximum" concept and allocate based on the "maximum historical baseline emissions."

Finally, EPA's unreasonable compliance deadlines leave inadequate time for sources to implement compliance plans, much less install new emission controls to meet the requirements. As noted in Southern Company's comments on the proposed Transport Rule, installing flue gas desulfurization (FGD) and selective catalytic reduction (SCR) cannot be accomplished by 2014, much less 2012.[3] Therefore, installing new emission controls to limit emissions is not a compliance option at the outset of this program. The compliance difficulties are exacerbated considering EPA is proposing to render existing CAIR allowance banks unusable for compliance with the Transport Rule. Presuming that trading will ultimately be allowed in the Transport Rule, early markets will be very limited, shallow, volatile, unreliable, and cannot presently be economically analyzed as a compliance alternative. With compliance options so limited, it is imperative that initial Transport Rule allowance allocations go to units **based on need.** Further, one EPA FIP allocation methodology cannot possibly address the myriad of unit needs as efficiently and fairly as states can individually for their affected sources.

In sum, allocations should reflect actual emissions. EPA's heat-input methods do not accomplish that objective as drafted. If EPA chooses to stick with the heat-input method, it must refine its emission constraint and issue a supplemental proposed rule for comment.

[3] Southern Company's experience has shown that it takes an average of 54 months to install a single FGD and an average of 36 months to install a single SCR.

IV. EPA's Proposed Changes to the Assurance Provisions to a DR-by-DR Basis Appear to be More Straight-Forward, but the Penalties Applied Under the New Allocation Options Would be Disproportionately Shared by the Higher Emitting Units

In the NODA3, EPA requests comment on two issues relating to the assurance provisions of the proposed Transport Rule. Specifically, EPA requests comment on implementing the proposed assurance provisions on a designated representative-by-designated representative basis, rather than owner-by-owner basis. EPA also asks for comment on the implications that the alternative allocation methodologies might have on the proposed assurance provisions and the reasonableness of using the proposed assurance provisions with the alternative allocation methodologies.

First, Southern Company agrees with EPA's decision to consider applying the allowance surrender requirement of the proposed assurance provisions on a DR-by-DR basis, rather than an owner-by-owner basis. This approach appears to be more straight-forward and more in line with the approach taken in other aspects of the proposed Transport Rule and other interstate trading programs. However, EPA should be cautious not to include language that would undermine any agreements between joint owners or otherwise set expectations that the actual penalty allowance obligations should not be tied to ownership.

Lastly, it appears that the assurance provisions under either of the heat-input allocation schemes would be disproportionately shared by the higher emission-rate units. As discussed in Section III of these comments, the heat-input methods yield a windfall of allowances to lower emission rate units (e.g., natural gas). In many cases, these units are allocated well over 500 times what they could possibly emit (e.g., SO2). Higher emission-rate units (e.g., coal) are significantly under allocated. The assurance provisions come into play when a state exceeds its budget plus variability. Therefore, if a state experiences an unusually high demand year and exceeds its budget plus variability, a significant portion of the penalty allowances will be owed by the under-allocated units. As noted earlier, the heat-input allocation method--without more consideration of actual emissions--leads to absurd results and disproportionately applies the assurance provision penalties on the higher-emitting units.

V. Flaws Still Exist in EPA's Underlying Data

Although the unit ID errors identified in the proposed Transport Rule appear to be correct in the NODA3, data flaws still exist. Below are specific examples of flaws that we identified. However, due to having only 30 days to review the data, other errors may still be present in NODA3.

- The 2004 ozone season historical NOx emissions are incorrect. This is perhaps due to EPA pulling information from the CAMD database by program, i.e., the NOx SIP Call. In 2004, seasonal NOx compliance started on May 31, rather than May 1. EPA should use data from the entire ozone season, not just the data when the seasonal NOx program began.

- There are some unit-level heat input errors for units sharing a common stack. For example, in 2009 Branch Unit 1 heat input is over by 26,484 while Branch unit 2 is under by 26,482. Overall, Plant Branch as an entire facility is approximately correct. There are similar errors in seasonal heat input for 2007-2009 for Plants McDonough and Yates.