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1200 Pennsylvania Ave. NW.
Washington, DC 20460

Subject: Attention Docket ID No. EPA-HQ-OAR-2013-0602
Georgia EPD November 2014 Comments on the Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units

Dear Docket Coordinator:

The Georgia Environmental Protection Division (EPD) appreciates the opportunity to provide the following comments on the U.S. Environmental Protection Agency's (EPA) Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, also called the proposed Clean Power Plan (CPP) or 111(d). The proposal was published in the *Federal Register* on June 18, 2014 (79 Federal Register (FR) 34830).

On October 30, 2014, EPA issued a Notice of Data Availability (NODA, 79 FR 64543) in support of the proposed CPP. The NODA provided additional information on several topics, and solicited comment on those topic areas. EPD's comments include some of the issues raised in the NODA.

Executive Summary

The utilities that provide electricity in Georgia include Georgia Power, an investor-owned utility, Oglethorpe Power, owned by 38 electric membership cooperatives (EMCs), Municipal Electric Authority of Georgia (MEAG), a public power entity created by an Act of the Georgia General Assembly in 1975 that represents 49 municipal utilities, Dalton Utilities and several independent power producers. Additionally, 10 counties in north Georgia are served or partially served by the Tennessee Valley Authority (TVA).

EPA's CPP proposal establishes emission guidelines, which reflect EPA's determination of best system of emission reduction (BSER), for states to follow in developing plans to address greenhouse gas emissions from existing fossil-fired electric generating units (EGUs). The specific greenhouse gas pollutant regulated in the proposal is carbon dioxide (CO_2). The proposal establishes four building blocks as BSER for existing utilities. The building blocks are: heat rate improvements at coal-fired EGUs; increased dispatch to natural gas combined cycle units (NGCCs), increased renewable energy and increased energy efficiency. EPA states in its proposal that the building block approach provides flexibility to states in deciding how to achieve the statewide standards.

As discussed in these comments and the comments submitted by EPD on September 16, 2014 on under-construction nuclear, the CPP does not provide flexibility to Georgia. In fact, the CPP is inflexible and punitive to states that have taken early action to reduce CO_2 emissions. The CPP has the potential to put Georgia at a competitive disadvantage relative to other southeastern states.

Georgia has taken significant early action to reduce CO_2 emissions from the electricity generation sector. In Georgia, 3,332 MW of coal-fired generation has either retired or been announced for retirement since 2010. In addition, almost 700 MW of coal-fired generation will be converted to natural gas by 2016. Georgia's utilities have invested in air pollution controls for the remaining coal units to comply with Georgia's Multipollutant Rule (sss), and the federal Mercury Air Toxics Standards (MATS) and Clean Air Interstate Rule/Cross State Air Pollution Rule CAIR/CSAPR. The accompanying reductions in sulfur dioxide, oxides of nitrogen, and mercury have resulted in significant improvements in air quality for ozone, fine particulate matter, and regional haze. Utilities have also invested in heat rate efficiency projects at the remaining coal units to optimize their efficiency for their remaining useful life. As a result of the retirements, conversions and investments in Georgia's energy sector, **CO_2 mass emissions in Georgia declined 33% between 2005 and 2012**. Unfortunately the CPP as proposed fails to give Georgia credit for the early action taken to reduce CO_2 emissions in Georgia. Instead, based on Georgia's CPP goal, EPD projects CO_2 emissions reductions from 2005 – 2030 of 46%. This is the highest percentage of CO_2 reductions in the Region 4 states, and well above the 30% nationwide average that the rule is expected to achieve.

EPD's key concerns and recommendations for improving the CPP include:

- The proposed rule's inclusion of under-construction nuclear generation in the state emission performance goal calculation minimizes flexibility in achieving the goal by means of other BSER building blocks.
- The across the board Heat Rate Improvement (HRI) goal of 6% in Building Block 1 is unlikely to be attainable in Georgia.
- EPA misinterpreted North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) when setting the renewable energy target for Georgia and other Southeastern states. Based on North Carolina's REPS, Georgia's RE target should be **no more than 7.5%**.
- The proposed rule penalizes states that took early action to reduce GHG emissions. The baseline year should be set somewhere in the 2005 to 2007 time frame to give Georgia and many other states credit for early action. This baseline period is also more appropriate since it predates the recession and would be more reflective of normal energy demand.
- EPA should correct the methodology for the rate-based to mass-based goal translation so that both approaches result in similar level of actual CO_2 mass emission reductions from the baseline.
- EPD does not support the alternative method for calculating states' goals suggested in the Notice of Data Availability issued on October 30, 2014. That calculation methodology only serves to make the ambitious goals of the original proposal even more stringent and much more difficult to achieve.
- EPA should replace the interim emission rate requirement with a non-enforceable state developed glide path. If the interim goal is retained, the start date of the interim period should be pushed back to five years after EPA's approval of the state plan.

EPD encourages EPA to structure the final rule in a way that rewards states that have taken early action to reduce CO_2 emissions, and encourages innovative approaches towards the goal of reducing CO_2 emissions from EGUs. EPA estimates the proposed rule will achieve annual CO_2 emission reductions of 26% - 30% below 2005 levels. This is **approximately 600 – 700 million metric tons of CO_2 reductions per year.** Given the "big picture" of massive CO_2 emission reductions over a 15 year period, EPD urges EPA to focus on the goal of achieving those reductions, and encouraging and enabling the use of all available tools that states can use to meet their targets. Overly prescriptive administrative and regulatory processes can create obstacles and disincentives to deploy certain approaches and also burden states and the affected EGUs with unnecessary monitoring, recordkeeping and reporting requirements.

Comments Related to Goal Computation

1. The proposed rule's inclusion of under-construction nuclear generation in the state emission performance goal calculation minimizes flexibility in achieving the goal by means of other BSER building blocks.

On page 34838 of the proposal, EPA states that:

> *"The proposed guidelines provide states with options for meeting the state-specific goals established by the EPA in a flexible manner that accommodates a diverse range of state approaches. The plan guidelines provide the states with the ability to achieve the full reductions over a multi-year period, through a variety of reduction strategies, using state-specific or multi-state approaches that can be achieved on either a rate or mass basis."*

As noted in our under-construction nuclear comments submitted on September 16, 2014, the way nuclear generation ultimately impacts the goal and achievement of the goal is fundamentally different than the other building blocks. A small shortfall in implementation of renewable energy, energy efficiency, or heat rate improvement should be of a magnitude that can be realistically compensated by overachieving in one of the other BSER blocks. However, under-construction nuclear generation has such a significant impact on emissions performance that a failure to complete the project or failure of the project to achieve the predicted generation rate would be virtually impossible to overcome. The way that under-construction nuclear is treated in the proposed rule significantly shrinks the "headroom" Georgia has for meeting either the interim or the 2030 goals.

Table 1 below breaks down EPA's proposed building block approach for application of the Best System of Emission Reduction (BSER) to Georgia's CO_2 emissions. Thirty-one (31%) percent of the 2012 – 2030 emissions rate reduction is associated with implementation of BSER Building Block 3a, under-construction nuclear. Achievement of Georgia's emissions goal therefore requires completion of construction, startup, and successful operation of Vogtle Units 3 and 4 at their forecast generation rates.

Table 1 - EPA's Proposed BSER Targets for Georgia's Goal and Associated Emissions Rate Improvements

BSER target (Building Block)	Description	Adjusted Emissions Rate (lbs CO2/MWh)	Rate Improvement (Block to Block)	2012 to 2030 improvement %
Baseline	Unadjusted 2012 emissions rate	1598	NA	NA
1	Coal EGU heat rate improvements to 6 %	1527	71	9
2	Natural gas CC dispatch increased from 51 % to 70 %	1298	228	30
3a	Under-construction nuclear (total of 2235 MW)	1064	235	31
3b	At-risk nuclear – 6 % of generation from 4 existing nuclear units	1044	20	3
3c	Renewable energy (increase from 3 % to 10 %)	926	118	15
4	Energy efficiency programs (increase from 0.67 % to 9.8 %)	834	92	12

In summary, the inclusion of under-construction nuclear in the State of Georgia's emissions performance goal eliminates flexibility in achieving the goal by means of other BSER building blocks. EPA should remove under-construction nuclear generation from the computation of BSER and state emissions goals. Furthermore, EPA should retain under-construction nuclear in the definition of affected entity for the purposes of demonstrating compliance in a state plan. For additional information, see Georgia's comments on under-construction nuclear submitted to the docket on September 16, 2014.

2. The across the board Heat Rate Improvement (HRI) goal of 6% in Building Block 1 is unlikely to be attainable in Georgia.

HRI projects affect a limited number of large coal-fired units that have, in some cases, already undertaken equipment upgrades and operational improvements.

EPA recognizes in its GHG Abatement Measures Technical Support Document (TSD) (page 2-4) that higher cost HRI projects are more effective and economically feasible for larger coal-fired units due to economies of scale. Georgia has only 10 coal-fired units greater than 500 MW not slated for retirement[1] that would be ideal for the "equipment upgrades" defined on page 34859 (Section VI.C.1.a.) of the proposal; however some have already completed higher cost upgrades. The 10 large coal-fired units are located at Georgia Power Company's Plant Bowen (4 units), Plant Scherer (4 units), and Plant Wansley (2 units). High-cost equipment upgrades including steam turbine overhauls, took place at Bowen Unit 1, Scherer Unit 1 and Scherer Unit 4 as recently as 2010[2].

According to EPA's GHG Abatement Measures TSD (TSD page 2-12, Table 2-2) steam turbine overhauls achieve the highest reported efficiency increases, yet Georgia will not be able to count recent turbine overhauls towards its state goal because the projects took place before 2012. EPD believes that HRI investments of this magnitude at the two largest plants in the state (Plant Bowen and Plant Scherer) will not reoccur in the near future. Furthermore, as stated in the 2009 Sargent & Lundy study (page 3-2) used by EPA to set the HRI goal, similar turbine retrofits at smaller coal-fired units are cost prohibitive and thus unlikely.

Diminishing returns, decreasing capacity factors, and EPA's baseline year make reaching the HRI goal more difficult.

On page 34859 (Section VI.C.1.a.) of the proposal, EPA states, based on the 2009 Sargent & Lundy study that it:

> *"…believes that implementation of all identified best practices and equipment upgrades at a facility could provide total heat rate improvements in a range of approximately 4 to 12 percent."*

The 2009 Sargent & Lundy study looked at the potential for HRI improvements prior to 2008, when many HRI projects considered **low hanging fruit** were not yet implemented. EPD believes that many of the more feasible and cost effective HRI projects have already been accomplished and the law of diminishing returns will make achieving similar HRI targets difficult in the future. A review of EPA's own TSD (Table 2-4, page 2-18) shows a tapering off of heat rate improvements since 2010. EPA studied a population of almost 900 coal- and petroleum coke-fired EGUs from 2002 through 2012 (TSD, page 2-16) and found that most heat rate improvements occurred prior to 2008 (TSD Table 2-4 page 2-18), in the same timeframe covered by the 2009 Sargent & Lundy study.

Also, EPA recognized that coal-fired generation and capacity factors (TSD page 2-20) have steadily decreased since 2008, in part due to the recession but also due to more natural gas and renewable generation. EPA states that *"16% of the change in hourly heat rate is attributable to capacity factor"* (TSD page 2-25). Capacity factors associated with coal-fired generation are likely to decline even more as the Clean Power Plan is implemented as a result of re-dispatching, increasing renewable generation

[1] Georgia Power Company plans to retire 15 coal and oil generating units totaling 2,061 MW according to the January 31, 2013 Integrated Resource Plan (IRP) filing to the Georgia Public Service Commission.
[2] An additional five coal-fired EGUs with capacities below 500 MW are projected to remain operational

or improving demand-side energy efficiency. Therefore achieving higher heat rate improvements, or even maintaining current heat rate performance, will prove difficult.

Finally, because EPA chose a baseline year of 2012, Georgia will not be able to count large equipment upgrades and operational improvements that took place before 2012 towards meeting its state goal. Many large investments in operational improvements and equipment upgrades took place in Georgia from 2008 through 2012 to comply with GA Rule 391-3-1-.02(2)(sss) – Multipollutant Control for Electric Utility Steam Generating Units.[3]

Parasitic load increases from the installation of new air pollution control equipment tend to offset HRI gains and make reaching the HRI goal more difficult.

As EPA stated in its GHG Abatement Measures TSD (TSD pg. 2-4), *"air pollution control equipment reduces the overall efficiency"* of electric generating units (EGU) by increasing parasitic load. In 2010, equipment upgrades conducted at the two largest coal-fired power plants in Georgia were at least partially offset by parasitic load increases from new air pollution control equipment needed to meet GA Rule 391-3-1-.02(2)(sss) – Multipollutant Control for Electric Utility Steam Generating Units. Other rules such as the Mercury and Air Toxics Standards rule (MATS) will require additional air pollution control equipment by 2016 that could increase parasitic load as well. As more air pollution control equipment is added to comply with forthcoming rules, many investments in unit efficiency will be offset to some degree by increasing parasitic loads that make reaching the HRI goal of 6%, based on net electric output, more difficult.

Building Block 2 works against the effectiveness of Building Block 1.

Building Block 1 requires heat rate improvements at coal-fired units to reduce carbon dioxide emissions. These efficiency improvements are offset by Building Block 2, which requires the coal-fired units to operate at a reduced capacity so that the natural gas dispatch to natural gas combined cycle (NGCC) can be increased from 51% to 70% in Georgia. Coal-fired units are designed for base load power, and operate most efficiently at higher rates. Operating the coal-fired units at reduced rates will prevent realization of any carbon dioxide reductions achieved by the heat rate improvement projects.

For Building Block 1, EPD recommends that EPA reassess the presumption that 6% HRI is achievable as an average of all coal-fired units, and instead require states to include in their state plans a unit-by-unit assessment of what HRI is cost effective and achievable. State goals would be adjusted accordingly.

3. EPA misinterpreted North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) when setting the renewable energy target for Georgia and other Southeastern states. Based on North Carolina's REPS, Georgia's RE target should be no more than 7.5%.

[3] Air pollution equipment (i.e. selective catalytic reduction, scrubbers and baghouses) added to comply with Georgia Rules for Air Quality Control 391-3-1-.02 (sss) - Multipollutant Control for Electric Utility Steam Generating Units.

EPA based the Southeast regional renewable energy target of 10% on North Carolina's REPS. However, the North Carolina standard contains provisions which allow both renewable energy and energy efficiency measures to satisfy the requirements.[4]

On page 34851 of the proposed rule, EPA states that:

> *"The EPA has reviewed information about the current and recent performance of affected EGUs and states' implementation of programs that reduce CO_2 emissions from these sources. Based on our analysis of that information, the proposed state goals reflect the following stringency of application of the measures in each of the building blocks: …… block 3, including the projected amounts of generation achievable by ….increasing renewable electric generating capacity over time through the use of state-level renewable generation targets consistent with renewable generation portfolio standards that have been established by states in the same region" [Emphasis added]*

EPA's Southeast Regional RE Target is based on North Carolina's (NC) REPS Primary Target of 12.5% for Investor Own Utilities (I.O.U's) by 2021 and thereafter. North Carolina's RPS statute §62-133.8. (b)(2) states that *"[a]n electric public utility may meet the requirements of this section by any one or more of the following"* including:

> *…(b) Use a 'renewable energy resource' to generate electric power at a generating facility other than the generation of electric power from waste heat derived from the combustion of fossil fuel.*
>
> *(c) Reduce energy consumption through the implementation of an energy efficiency measure; provided, however, an electric public utility subject to the provisions of this subsection may meet up to twenty-five percent (25%) of the requirements of this section through savings due to implementation of energy efficiency measures. Beginning in calendar year 2021 and each year thereafter, an electric public utility may meet up to forty percent (40%) of the requirements of this section through savings due to implementation of energy efficiency measures…*

North Carolina's statute has defined 'renewable energy resources' (in (b) above) to include over 16 different potential fuels that are not known to be significant or sustainable renewable resources in Georgia. By comparison, EPA states that "*The East Central and Southeast regions show moderate to strong resources in both biopower and rooftop PV potential."*[5] Paragraph (c) of the statute states that up to 40% of the North Carolina 12.5% RPS target can be met by the implementation of energy efficiency measures, which translates to an effective RE target of 7.5%.

Also, it is worthwhile to note that North Carolina's REPS Secondary Target for electric membership corporations and municipalities is 10% by 2018 and thereafter. North Carolina's REPS statute § 62-

[4] North Carolina Statute (G.S. 62.133.8), http://www.ncleg.net/EnactedLegislation/Statutes/HTML/BySection/Chapter_62/GS_62-133.8.html
[5] U.S. EPA, Greenhouse Gas Abatement Measures TSD, Section 4.2.2.2

133.8(c)(2) states that *"An electric membership corporation or municipality may meet the requirements of this section by any one or more of the following"* including:

> *(c) Purchase electric power from a renewable energy facility or a hydroelectric power facility, provided that no more than thirty percent (30%) of the requirements of this section may be met with hydroelectric power, including allocations made by the Southeastern Power Administration.*

In this case North Carolina's REPS allows the use of up to 30% of existing electric hydro generation to be counted towards the 10% REPS target. In EPA's proposal the use of existing electric hydro generation is not allowed; so the exclusion of hydro generation would effectively reduce the comparable RE secondary target to 7% for EMCs.

Because of the inconsistencies between the handling of renewable energy in the proposed § 111(d) rule and the flexibilities incorporated in North Carolina's REPS, Georgia EPD believes that EPA misinterpreted the North Carolina requirements when setting the renewable energy target for Georgia and other Southeastern states. <u>Based on North Carolina's REPS, Georgia's RE target should be no more than 7.5%.</u>

4. **The proposed rule penalizes states that took early action to reduce GHG emissions. The baseline year should be set somewhere in the 2005 to 2007 time frame to give Georgia and many other states credit for early action. This baseline period is also more appropriate since it predates the recession and would be more reflective of normal energy demand**.

The CPP penalizes the states that took early action to reduce CO_2 emissions.

States that expanded their NGCC capacity prior to the proposal are being penalized by the BSER requirements of Building Block 2. Table 2 below compares Georgia's NGCC capacity and 2012 NGCC utilization to that of other Region 4 states. For Georgia, 30% of our total CO_2 emission reduction goal is dependent on increased natural gas dispatch. However, one Region 4 state is not required to do any natural gas dispatch – Kentucky. Kentucky has no NGCC units, so Block 2 BSER does not apply to Kentucky. This example illustrates the unfairness of this proposal. States with the largest NGCC dispatch changes will incur the higher costs for their CO_2 reduction.

Table 2: Region 4 States Natural Gas Combined Cycle Dispatch

Region 4 State	2012 NGCC Capacity (MW)	2012 NGCC Capacity Factor*	Post Re-dispatch Assumed NGCC Capacity Factor for Existing Fleet
Alabama	10,333	59%	70%
Florida	29,485	51%	70%
Georgia	**8,355**	**51%**	**70%**
Kentucky	0	N/A	N/A
Mississippi	7,894	46%	63%
North Carolina	4,709	37%	70%
South Carolina	2,839	45%	70%
Tennessee	1,601	47%	70%

Table 3 below summarizes the CO_2 mass emissions in the years 2005, 2012, and 2030 and associated mass emission reductions for the Region 4 states. The year 2005 was included because EPA, in the rule preamble, states that the CPP will achieve a nationwide 30% reduction in CO_2 emissions between 2005 and 2030. EPD projected 2030 emissions for the southeastern states using values for the 2030 rate-based goals and generation from the CPP's Goal Computation TSD. See Method 2(a) in Comment 5 of this document for more details. The projection for Georgia reflects a CO_2 emissions reduction from 94.1 million tons in 2005 to 51 million tons in 2030, a 46% reduction. This is the highest percentage of CO_2 reductions in the Region 4 states, and well above the 30% nationwide average that the rule is expected to achieve. In fact, Georgia already reduced CO_2 mass emissions by 33% from 2005 – 2012. This example illustrates the unfairness of this proposal. States that took early action to reduce CO_2 emissions are being penalized by the proposed CPP. The wide range in projected CO_2 mass reductions within the region has the potential to provide some states with an economic advantage over states with very high CO_2 emission reduction projections, like Georgia.

Table 3: CO_2 Mass Emissions and Emission Reductions in Region 4 States

State	2005 CO_2 Emissions, (tons)	2012 CO_2 Emissions, (tons)	2030 CO_2 Emissions (proj. tons)*	Reduction 2005-2012 (%)	Reduction 2005-2030 (%)	Reduction 2012-2030 (%)
Alabama	91,471,965	75,571,780	66,159,219	17%	28%	12%
Florida	136,497,129	118,507,699	89,610,477	13%	34%	24%
Georgia	**94,101,017**	**62,850,673**	**50,964,092**	**33%**	**46%**	**19%**
Kentucky	100,174,369	91,373,788	86,434,979	9%	14%	5%
Mississippi	27,712,055	25,903,885	21,200,127	7%	23%	18%
N. Carolina	75,581,180	58,609,217	51,179,702	22%	32%	13%
S. Carolina	44,739,634	35,896,910	30,352,773	20%	32%	15%
Tennessee	60,533,661	41,237,327	36,784,640	32%	39%	11%

* 2030 CO_2 projections based on product of rate-based goals and generation from the CPP's Goal Computation TSD

5. EPA should correct the methodology for the rate-based to mass-based goal translation so that the rate-based and mass-based goal approaches result in similar levels of actual mass CO2 reductions compared to the baseline year. The final year generation used for the mass-based goal should be based upon nationally recognized demand projection data such as EIA's Annual Energy Outlook (AEO).

The concept in the proposed rule for translating a rate-based goal to a mass-based goal is erroneous as stated and will significantly penalize a state that opts for a mass-based goal. This concept is currently defined in paragraph (a)(3) of proposed rule § 60.5770 and elaborated in the "Projecting EGU CO_2 Emission Performance in State Plans" TSD.[6] The rule language is as follows:

> *"60.5770 What is the procedure for converting my state rate-based CO_2 emission performance goal to a mass-based CO_2 emissions performance goal? ……*
>
> *(a)(3) The conversion must represent the tons of CO_2 emissions that are projected to be emitted <u>by affected EGUs</u> [emphasis added], in the absence of emissions standards contained in the plan, if <u>the affected EGUs</u> [emphasis added] were to perform at an average lb CO_2 /MWh rate equal to the rate-based goal for the state identified in Table 1 of this Subpart."*

"Affected EGU" is defined in proposed rule § 60.5820 and for most states, including Georgia, the affected EGUs are coal-fired steam units, gas-fired steam units, and NGCC units. **Our interpretation of the paragraph (a)(3) rule language is that the 2030 mass-based goal would be determined by taking the product of 834 lbs. CO_2/MWh (Georgia's rate-based goal in Table 1 of the rule) and the projection of 2030 generation from affected EGUs only.** However, the method of calculating the rate-based goal of 834 lbs. CO_2/MWh is based upon generation from <u>all affected entities</u> (defined in § 60.5820 and including nuclear, RE, and EE), not just from affected EGUs.

EPD interprets proposed rule § 60.5770 as describing the following calculation:

Mass goal = (emiss. rate based on EGUs + nuclear + RE + EE) *x (generation from EGUs)* ***[Method 1]***

However, the calculation should be performed as:

Mass goal = (emiss. rate based on EGUs + nuclear + RE + EE) *x (generation from EGUs + nuclear + RE + EE)* ***[Method 2]***

[6] U. S. EPA, June 2014, Projecting EGU CO_2 Emission Performance in State Plans, Technical Support Document for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Docket ID No. EPA-HQ-OAR-2013-0602

Since the generation used in Method 1 will be significantly smaller than that of Method 2, the resulting mass goal for Method 1 will be erroneously low.

For purposes of illustration, mass-based goals were calculated using the two methods above, which differ only in the selection of the 2030 generation used in the calculation. Method 1 uses generation from affected EGUs only, as described by proposed rule § 60.5770. The 2030 EGU generation is the sum of historic (2012) coal and NGCC generation taken from EPA's Clean Power Plan file "20140602tsd-goal-data-computation-1.xls."[7] This proxy for projected 2030 generation from existing EGUs is reasonable since, in a reduced CO_2 regulatory environment, there is no expectation of growth in fossil-fired generation. Method 2(a) uses generation from all affected entities, which is taken from file "20140602tsd-goal-data-computation-1.xls." Conceptually, it would seem that this method will result in the mass that is the true equivalent to the rate-based goal of 834 lbs. CO_2/MWh. Method 2(b) also uses generation from all affected entities, but was determined by starting with total demand projections from EIA's 2014 Annual Energy Outlook (AEO)[8] for the SERC Southeastern (SERC-SE) region. More detail on the calculation of 2030 generation is provided in Attachment A.

In Table 4 below, the mass-based emissions goals calculated by Methods 1, 2(a), and 2(b) are compared to Georgia's actual 2005 and 2012 emissions - 91,101,000 tons and 62,850,000 tons, respectively. Method 1 (proposed rule § 60.5770 method) shows a 65 % reduction from 2005, whereas Methods 2(a) and 2(b) show 46 % and 44 % reductions, respectively. Method 1 shows a 48 % reduction from 2012, whereas Methods 2(a) and 2(b) show 19 % and 16 %, respectively. Clearly the mass-based goal calculated in Method 1 is significantly and inappropriately low. The Method 1 reduction from 2005 actual emissions would be more than double the nationwide 30 % reduction that EPA has stated (page 34832 of the proposal) will be achieved by the Clean Power Plan.

Table 4: Comparisons of 2030 Mass-based Goal Computations to 2005 and 2012 Actual Emissions

Method	**2030 generation basis (MWh)**	**2030 CO_2 emissions goal (tons)**	**Reduction from 94,101,000 tons (2005 CO_2 emissions)**	**Reduction from 62,850,000 tons (2012 CO_2 emissions)**
1 – proposed rule § 60.5770 basis; affected EGU generation	78,563,213 Goal Comp. TSD	32,761,000	65 %	48 %
2(a) - affected entity generation	122,216,047 Goal Comp. TSD	50,964,092	46 %	19 %
2(b) – affected entity generation	126,099,000 AEO projection	52,583,000	44 %	16 %

[7] file "20140602tsd-goal-data-computation-1.xls" Goal Computation Technical Support Document, Appendix 1 – State level goals, underlying state level data, and calculations for the proposed state goals

[8] Annual Energy Outlook 2014, Release Date May 7, 2014, Electricity and Renewable Fuel Tables, Table 86. SERC Reliability Corporation / Southeastern (http://www.eia.gov/forecasts/aeo/tables_ref.cfm)

Based on these calculations, EPD believes that the mass-based calculation concept in proposed rule § 60.5770(a)(3), is erroneous as stated. Section III.A of the "Projecting EGU CO_2 Emission Performance in State Plans" TSD reiterates the same concept of applying the Subpart UUUU Table 1 rate-based goal, determined from all affected entities, to the 2030 generation of affected EGUs only. <u>EPD believes that the mass-based goal should be calculated as the product of the affected entity emissions rate (from Blocks 1 - 4 of the Goal Computation TSD) and the projected 2030 affected entity generation. The final year generation used for the mass-based goal should be based upon nationally recognized demand projection data such as EIA's Annual Energy Outlook (AEO).</u>

Georgia EPD requests that EPA develop a method of translation to a mass-based goal that is straightforward, uniform for all states, and more comparable to the method for computing the existing rate-based goals. The guidance that EPA has provided in two separate TSDs is inadequate.

Section III of EPA's technical support document (TSD) titled "Projecting EGU CO_2 Emission Performance in State Plans" discusses the method for "translating" from a rate-based goal to a mass-based goal. The translation method is discussed further in a second TSD titled "Translation of the Clean Power Plan Emission Rate-based CO_2 Goals to Mass-based Equivalents**".** For simplicity, the above-referenced TSDs will be called the "Emission Performance TSD" and the "Translation TSD" in this comment document. Comments on the Emission Performance TSD are discussed immediately below and are followed by comments on the Translation TSD.

Georgia EPD agrees that the determination of a mass-based goal should be a simple translation of the rate-based goal. Generally accepted meanings of "translate" are to express something in different words or to change something from one form to another. By extension, it follows that the mass-based goal that is the translation of the rate-based goal should be based on the same assumptions and methodology as the rate-based goal. However, Section III of EPA's Emission Performance TSD appears to be proposing a method that is based on different assumptions than the rate-based goal and based on more extensive analysis than the rate-based goal. The degree of flexibility allowed in the method as proposed seems to allow for potential wide variability in the resulting mass-based goal determination, whereas EPD believes that determination of a compliance goal should be repeatable and uniform.

Section III.B of the Emission Performance TSD states the following:

> *"As described above, the projection scenario for translating from a rate-based CO_2 emission performance goal to a mass-based CO_2 emission performance goal does not include requirements, programs, and measures included in a state plan. Construction of this scenario must therefore carefully consider treatment of eligible "on-the-books" state requirements, programs and measures included in the state plan."*

In comparison, the Goal Computation TSD lays out the method that EPA used to compute the state rate-based emissions performance goals. The method is based on the following:

- A historical baseline of 2012 CO_2 emissions for each state
- Computation of a historical 2012 CO_2 emissions rate for each state
- Determination of target levels of achievable reductions (BSER) for each state
- Adjustment of the 2012 emissions rate to a 2030 rate by application of these achievable reductions

The Goal Computation TSD does not *"consider treatment of eligible 'on-the-books' state requirements, programs and measures included in the state plan"* as is discussed in the Emissions Performance TSD for determining a mass-based goal. Therefore, the Emissions Performance TSD seems to contemplate more extensive analysis for determining a mass-based goal than was performed for the rate-based goal. The inclusion of "on-the-books state requirements, programs and measures" in formulating the "Reference Case Scenario" and the "Goal Policy Scenario" of Section III.B of the Emission Performance TSD appears to make the underlying assumptions for the mass-based goal more restrictive on emissions than the assumptions for the rate-based goal.

Furthermore, the contemplation of *"programs and measures included in the state plan"* to calculate the mass-based goal implies that the state will already have an approved state plan prior to calculating the mass-based goal. This seems to confuse the establishment of a mass-based goal with the emissions performance projection (proposed rule § 60.5740(4)) that is required to demonstrate that a state plan will meet its goal. Obviously, states will need to have an established goal before they can put together the state plan programs and measures that will project compliance with the goal. In summary, Georgia EPD requests that EPA develop a method of conversion that is straightforward, uniform for all states, and more comparable to the method for computing the existing rate-based goals.

The existing affected source illustration in EPA's TSD "Translation of the Clean Power Plan Emission Rate-based CO_2 Goals to Mass-based Equivalents" produces a generation level that is not equivalent to the generation used to set the rate-based goal, resulting in a significant under-calculation of Georgia's mass-based goal.

In the calculation of the rate-based goal, EPA added incremental RE and EE and under-construction nuclear to historic (2012) fossil-fired generation, whereas the approach in the new TSD uses this new generation to simply replace fossil generation on a one-to-one basis. These methods are clearly not the same and the TSD method produces a generation level that is not equivalent to the generation used to set the rate-based goal. In order for a mass-based goal to be equivalent to a state's rate-based goal, the two computations must use the same generation level for the final goal year.

The existing affected source approach to calculating a "mass equivalent generation level" (reference Table 1 of the TSD) assumes that incremental RE, incremental EE, and under-construction nuclear will replace fossil generation on a one-to-one basis and result in 2029 generation of 83,753,805 MWh. In Attachment A to these comments, EPD has calculated the projected 2029 demand in Georgia to be 122,442,270 MWh, based on generation growth projections for the SERC-SE region (primarily Alabama and Georgia) in the AEO released May 7, 2014 (reference Electricity and renewable fuel tables, Table 86, Net energy for load" data)[9]. It should be noted that the "Translation" TSD calculates generation for 2029, whereas the final rate-based goal referenced in the proposed rule is for the year 2030 (reference proposed rule § 60.5740(a)(3)(i)).

In comparison, the AEO projected 2029 demand in Georgia is nearly identical to the 2030 generation used in EPA's rate-based goal calculation: 122,442,270 versus 122,216,047 MWh. Based on AEO projections, the approach described in the new TSD (83,753,805 MWh) is a significant under-representation of expected 2029 demand in Georgia and results in a significant under-calculation of Georgia's mass-based goal. The approach used in calculating the rate-based goals, in which incremental RE and EE and under-construction nuclear add to (rather than replace) fossil-fired generation, appears to be more appropriate.

The final mass equivalent calculated for Georgia in the Translation TSD is 31,676,000 metric tons (34,843,000 short tons), which represents a 63% reduction from 2005 actual CO_2 emissions and a 38% reduction from 2012 actual CO_2 emissions. This is clearly unreasonable and is well beyond the nationwide reductions expected from the June 2014 proposed rule (30% reduction from 2005). Table 5 below shows 2029 generation levels and mass emissions associated with several goal computation methods.

Table 5: Final generation and CO_2 mass emissions for selected goal calculation approaches

Goal approach/form	2029 generation (MWh)	2029 CO_2 emissions (tons)*
Goal Translation TSD – Tables 1 & 4	87,753,806	34,843,000
Goal Computation TSD	122,216,047	50,964,092
AEO Projection, 2012 to 2029	122,442,270	51,058,427

* assuming rate-based goal of 834 lbs CO_2/MWh

<u>In summary, the Translation TSD produces a generation level that is not equivalent to the generation used to set the rate-based goal or the generation projected using AEO's demand forecast, resulting in a significant under-calculation of Georgia's mass-based goal. The goal translation methodology should be corrected to produce a mass-based goal that is equivalent to a state's rate-based goal. To accomplish this equivalency, the two computations must use the same generation level.</u>

6. EPD does not support the alternative approaches for calculating states' goals presented in Section III.C.1 of the Notice of Data Availability (NODA) issued on October 30, 2014. These approaches make the ambitious goals of the original proposal even more stringent and much more difficult to achieve, and they do not reflect expected demand growth in Georgia and other southeastern states.

[9] Annual Energy Outlook 2014, Release Date May 7, 2014, Electricity and Renewable Fuel Tables, Table 86. SERC Reliability Corporation / Southeastern (http://www.eia.gov/forecasts/aeo/tables_ref.cfm)

EPA issued a NODA pertaining to certain aspects of the Clean Power Plan on October 30, 2014. In Section III.C.1 of the NODA, EPA invites comment on implementation of the goal-setting equation with respect to the effect of incremental RE and EE generation on historical (2012) fossil-fired generation and emissions. In the original proposal, incremental EE and RE generation (from BSER Building Blocks 3 and 4) are added to the denominator of the goal equation without affecting the quantity of historical fossil generation that comes from BSER Building Blocks 1 and 2. It is apparently assumed that, going forward from 2012, the incremental EE and RE will satisfy demand growth and fossil generation will remain at 2012 levels.

In the NODA, EPA presents two possible alternatives to the original approach. In these alternative approaches, incremental RE and EE would replace historical fossil generation in one of the following ways: (a) on a pro rata basis, with fossil steam (i.e., coal) and NGCC generation reduced in proportion to historical levels, or (b) on the basis of highest-emitting (fossil steam) generation reduced first. For method (a), EPA does not speak to whether the pro rata reductions would be calculated prior to or after the redispatch to NGCC that is used for the basis of BSER Building Block 2. Georgia EPD has calculated the effects of method (b) on our emissions rate goal and on coal-fired generation in the state. The approach proposed in the NODA:

- Reduces the final goal from 834 to 566 lbs CO_2/MWh
- In combination with Building Block 2 redispatch, reduces fossil steam generation from 41,000 GWh in 2012 to 7000 GWh MWh in 2030 (an **83% reduction**)

Georgia EPD has estimated 2030 state-wide demand based on EIA's 2014 Annual Energy Outlook (AEO) projections for the southeast (see Table 4 of this comment letter). Our projection of demand in 2030 is very close (2% higher) to the generation calculated for the goal-setting equation in the original proposal's Goal Computation TSD. Therefore, we believe that all of the 2012 fossil-fired generation will be needed to meet demand in 2030 and that the new approaches described in the NODA are unrealistic for Georgia.

In summary, the alternative approaches presented in the NODA make Georgia's goal much more stringent and they assume a reduction in fossil steam generation that would seriously compromise the state's dispatch flexibility. In addition, they do not reflect expected demand growth in Georgia and other southeastern states and the need to retain a fossil-fired fleet that is adequate to meet the demand growth. <u>EPD does not support the alternative approaches for calculating states' goals presented in Section III.C.1 of the NODA.</u>

Comments on Implementation Issues

1. The natural gas infrastructure is not adequate in Georgia to support current demand and a 70 percent dispatch rate for NGCC.

On page 34863 of the proposal, EPA states:

> *"If the current pipeline and transmission systems allow these utilization rates to be achieved in peak hours and for extended periods, it is reasonable to expect that similar*

> *utilization rates should also be possible in other hours when constraints are typically less severe, and be reliably sustained for other months of the year."*

Although it has been demonstrated that a 70% dispatch rate can be achieved in peak hours, this scenario is based on base loads being achieved by other EGUs. If 70% dispatch of NGCC becomes part of the base load generation, it would reduce the available amount of standby, peak demand, and emergency based power. This proposal comes after extreme winter weather conditions hit the state in January of 2014 and caused record-setting winter electricity demands across north Georgia. In addition to the electricity demands during this period, natural gas demand for residential heating peaked. With the proposed 70% dispatch target, such future demands may have to be met with less efficient natural gas simple cycle turbines which would put additional stress on natural gas residential heating supplies.

As more natural gas goes into the production of electricity, the natural gas infrastructure may not be able to meet the natural gas demand during periods of high energy demand (winter heating season). Additional natural gas pipeline infrastructure is currently being built to keep up with existing demand and demand growth. However, there is growing public opposition to new natural gas pipelines. For example, Spectra Energy has proposed a 465-mile, $3.5 billion pipeline and compressor station (the Sabal Trail Pipeline) which is planned to run through parts of South Georgia. Green Law, Flint River Keepers and the local community are opposed to the pipeline and have challenged Spectra Energy and Federal Energy Regulatory Commission officials on the proposed route and site for the pipeline and pumping station. The officials have heard scores of negative comments from standing room only public information meetings. Joe Adgie of *The Valdosta Daily Times* writes,

> *"The proposed pipeline has been greeted by a massive level of opposition, with opponents expressing concern about the effects of the pipeline on their area. Protests have stretched across South Georgia since the pipeline was announced."*[10]

Growing public opposition and obstruction to new natural gas pipelines and pumping stations may prevent adequate natural gas infrastructure from being built within the time frame proposed in the CPP to meet a 70% dispatch rate for NGCC by 2020.

Georgia's NGCC fleet capacity is not adequate to support a reliable power grid and 70% dispatch rate for NGCC.

Existing NGCC units are strategically located in the state to aid in power grid balancing for reliable instantaneous demand. Currently, Georgia maintains a reliable power grid with NGCCs operated at a dispatch rate of over 51%. With the increased burden of NGCCs operated as baseline, future system reliability will be decreased. EPA's Clean Power Plan proposes to increase reliance on renewable power generation. Many of the existing renewable power technologies are intermittent renewables such as solar and wind. These intermittent power sources are dependent on daily weather and time of day. With the addition of intermittent power generation, there will be greater demand for rapidly dispatched power to maintain the balance and reliability of the grid. Requiring the existing NGCC fleet to meet base

[10] *Sabal Trail Protest Today*, Joe Adgie, Valdosta Daily Times, October 20, 2014

load demand **and** respond to renewable power supply fluctuations leaves very little flexibility and reserve capacity to ensure a reliable electrical supply for the citizens of Georgia.

<u>Based on the current and future demand on the existing and under-construction natural gas infrastructure and NGCCs and the economics and hurdles for the construction of new natural gas infrastructure and NGCCs, EPD believes the 70 percent capacity factor is not achievable by 2020, as required by the CPP. EPD believes that EPA should revise the CPP (specifically related to the interim goal) to allow states the flexibility of phasing in dispatch changes over time as long as the 2030 goal is met.</u>

The target for redispatch to NGCC should be phased in over a longer duration to allow for more cost-effective operation of existing fossil-fired generation sources.

EPA issued a Notice of Data Availability (NODA) pertaining to certain aspects of the Clean Power Plan on October 30, 2014. In Section III.A of the NODA, EPA invites comment on the 2020 to 2029 glide path to address concerns from stakeholders that *"… significant shifts of generation away from coal-fired generators to NGCC units (as calculated under Building Block 2) will be necessary by 2020 and will be difficult for at least some states to reasonably achieve in that timeframe*." EPA seeks comment on two specific modifications to the interim goal calculations that would provide for a more gradual phase-in of Building Block 2 during the interim period.

Georgia EPD is providing comment on the second suggested modification, which pertains to the pace with which generation may need to be shifted from coal-fired to NGCC units. Georgia EPD believes that EPA's proposed target schedule for Georgia is asking for too much, too soon. Georgia's redispatch from coal units to NGCC makes up 30 % of the overall reduction in our emissions rate reduction from 2012 to 2030 and is targeted by EPA for implementation by 2020.

EPA states that stakeholders have expressed concerns that moving generation away from existing assets, specifically coal-fired units, could limit cost-effective options by stranding these assets. Georgia EPD shares this concern. The NODA states:

> *"However, to the extent that stakeholders are concerned that the tools available to states under the proposal may, in some instances, be inadequate to address concerns regarding stranded investments, an additional way to address these concerns may be for the agency to take account of the book life of the original generation asset, as well as the book life of any major upgrades to the asset, such as major pollution control retrofits. For example, in its modeling, the EPA assumes a book life of 40 years for new coal-fired units."*

Between 2012 and 2016, Georgia is retiring over 3000 MW of coal-fired capacity. In January 2016, there will be 9400 MW of capacity remaining in its coal-fired fleet. Selective catalytic reduction (SCR) controls and flue gas desulfurization (FGD) controls will be installed on 95% of the remaining coal-fired generation capacity. The installation dates of these controls will range from 2001 to 2014. Assuming a 40-year book life for this equipment, the book life retirement dates will range from 2041 to 2054. These control systems should be viable assets for at least 21 years past 2020, the year that EPA has assumed redispatch to NGCC to be completed.

Redispatch away from coal-fired generation will result in a significant quantity of stranded viable assets. For example, according to EPA's modeling, Plant Scherer Units 1 and 2 will be retired by 2020 after recently installing nearly $500 million in air pollution control equipment. These units are partially owned (30%) by Georgia municipal utilities and (60%) Georgia's EMCs. Premature retirement of these units will leave small municipal utilities, and the Georgia citizens served by these utilities, with financial obligations for the installation of the air pollution control equipment extending for the next forty years without any benefit of electricity generation.[11] EPA should phase in the target for redispatch to NGCC over a longer duration to allow for continued, cost-effective operation of existing fossil-fired generation sources.

2. EPA should replace the interim emission rate requirement with a non-enforceable state developed glide path. If the interim goal is retained, the start date of the interim period should be pushed back to five years after EPA's approval of the state plan.

Remove the requirement for compliance with an interim goal and track emissions reduction progress by means of a voluntary glide path.

Georgia EPD views the requirements relating to the interim compliance period as onerous, unnecessary and a burdensome drain on resources. Proposed rule § 60.5740(a)(3)(i)(A) requires a state plan to identify the average emission performance level that will be achieved during the ten-year interim performance period of 2020 through 2029. The emission performance must be as good as or better than the interim goal of 891 lb CO_2/MWh. Proposed rule § 60.5775(c) requires a state to calculate and include in its state plan increments (projections) of emission performance for every two-rolling calendar year period during 2020 – 2029. The interim goal, which is a ten-year average, must be met at the end of 2029. Proposed rule § 60.5815 requires an annual report starting in 2021 that includes the emissions performance achieved by all affected entities (including EGUs). Furthermore, proposed rule § 60.5815(b) requires a comparison of the average two-year emission performance of all affected entities to the projected two-year performance established under proposed rule § 60.5775(c). Explanations and corrective actions must be provided for deviations greater than 10 percent.

In summary, there is a significant burden imposed by the interim compliance requirements:

- Projection of emission performance for nine two-year periods;
- Calculating and reporting of performance annually for ten years; and
- Comparison of performance to the projection annually for ten years with explanations and corrective actions, if needed.

It appears that this burden outweighs the intent of the interim goal, which is to move states toward compliance with the 2030 final goal. EPD sees no reason to require all of this administrative activity when tracking of progress along a glide path is so much simpler and achieves the same objective of demonstrating progress towards the ultimate 2030 goal.

[11] Letters to Mr. Judson H. Turner from Ronnie Johnston, Mayor of Covington (dated October 29, 2014), Ryan McLemore, Mayor of Griffin (dated November 10, 2014), and Jimmy Andrews, Mayor of Sandersville (dated October 31, 2014)

Georgia EPD therefore recommends that the interim compliance period and goal be replaced with a non-enforceable glide path. The glide path approach has been used successfully in EPA's Visibility Improvement (Regional Haze) program. The state-developed glide path would establish emissions performance targets that would be non-enforceable prior to 2030. Comparison of one-year emissions performance to the glide path would be conceptually more straightforward than comparison of performance to cumulative multiyear averages as currently proposed. States would have the responsibility to make adjustments as required to stay on track to meet the enforceable 2030 compliance target.

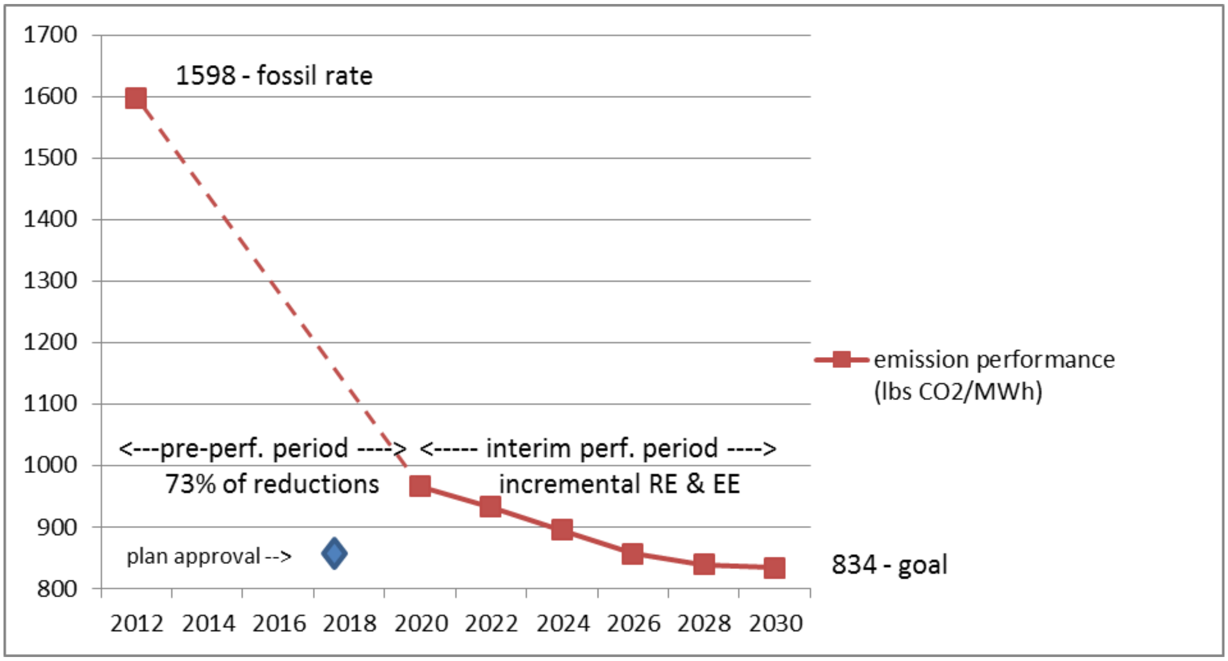
If the interim goal is retained, delay the start of the interim compliance period to five years after EPA's approval of the state plan.

Georgia EPD believes that the currently proposed interim period start of 2020, in combination with the stringent interim goal, requires actions on a schedule that is not realistic (too much, too soon). EPA invited comment on the start date at 79 FR 34905:

> *"A performance period is a period for which the state plan must demonstrate that the required emission performance level will be met. The EPA proposes a start date of January 1, 2020, for the interim goal plan performance period. This date would be the beginning of the 10-year period for which a state must demonstrate that the projected emission performance level of affected EGUs in the state, on average, will be equivalent to or better than the applicable interim goal. The agency generally requests comment on the appropriate start date and rationale."*

According to the emissions rate schedule published in the appendix to the Goal Computation TSD, Georgia's target for the 2020 calendar year would be 966 lbs. CO_2/MWh and the ten-year average interim goal is 891 lbs. CO_2/MWh (from the Goal Computation TSD). Although EPA states that there is flexibility to fall behind at the start of the period and make it up later, this would be very difficult to do in light of the cumulative averaging nature of the goal. The further a state is into the interim period, the harder it is to improve the average. EPA has targeted a reduction in emissions performance from 1598 lbs. CO_2/MWh in 2012 (fossil sources) to 966 lbs. CO_2/MWh in 2020 (see Figure 1 below) through implementation of all BSER except incremental RE and EE. This reduction amounts to 73 % of the overall reduction in Georgia's emissions rate reduction from 2012 to 2030. EPD sees no reason to require the significantly steep reductions in the first few years of a 15 year plan.

Figure 1. – CO_2 Reductions Required in Georgia Emissions Performance Targets Over Time, per EPA Goal Computation TSD



EPA's proposal therefore requires Georgia, and many other states, to make significant CO_2 emission reductions prior to 2020. Georgia must implement the following changes to its energy sector prior to 2020 in order to have a chance of meeting EPA's interim goal:

- Design, fund, permit, and construct the projects necessary to implement the heat rate efficiency improvements targeted by the proposal at the 15 coal-fired EGUs that will still be operating in 2020;
- Utilities must renegotiate a number of contracts to reduce the amount of coal burned while increasing the natural gas dispatch to 70%;
- Build the natural gas infrastructure necessary to achieve 70% natural gas dispatch (annual percentage) at all NGCC units;
- Complete the construction, testing, and startup of two new nuclear plants;
- Pass laws (potentially), promulgate rules, and design management systems to establish and track renewable energy and energy efficiency programs; and
- Increase energy efficiency savings by 0.2% per year (percentage of retail sales) beginning in 2017.

State plans are due to EPA by June 30, 2016. According to proposed rule § 60.5715, EPA will have until June 30, 2017, to approve or disapprove the state plan. Assuming that these two steps happen on schedule, only two and one-half years will remain until the proposed start (January 1, 2020) of the interim compliance period. As EPA will be tasked with reviewing 49[12] state plans simultaneously, it is

[12] Washington DC and Vermont are not required to submit state plans because they have no coal-fired EGUs.

likely that there will be delays in the approval process. Georgia EPD believes that there is simply not enough time to implement the actions listed above between plan approval and January 1, 2020. As stated above, EPD believes the interim goal should be replaced with a state developed glide path. <u>However if an interim goal is retained, EPA should move the start of the interim period to five years after EPA's approval of the state plan, and retain the starting emissions performance target and interim period average as set in the final rule.</u> This should allow time to implement the plan and achieve interim emission rates, while retaining an advance progress-tracking period of adequate length.

3. States should be able to take credit for Renewable Energy generated out of state and the existing REC markets should be used to prevent double counting.

A state should be able to take credit for renewable energy generated out-of-state as long as the state can verify that the generation has not been double-counted.

On page 34922 of the proposal, EPA states the following:

> *"…. The EPA is proposing that, for renewable energy measures, consistent with existing state RPS policies, a state could take into account all of the CO_2 emission reductions from renewable energy measures implemented by the state, whether they occur in the state or in other states. This proposed approach for RE acknowledges the existence of renewable energy certificates (REC) that allow for interstate trading of RE attributes and the fact that a given state's RPS requirements often allow for the use of qualifying RE located in another state to be used to comply with that state's RPS. …"*

Georgia EPD strongly supports the concept of allowing a state to credit generation from qualifying RE measures in another state toward the purchasing state's emission performance goal. The Georgia Public Service Commission approved Georgia Power's proposed agreement to purchase 250 MW of wind power by 2016 on May 20, 2014.[13] A contract has since been signed with an Oklahoma supplier. It is expected that Georgia will add even more wind generation purchased from other states to its renewable portfolio. Current analyses of in-state land-based wind generation show very limited potential. It is EPD's position that a state that is providing a market to another state with renewable resources should receive CPP credit for renewable energy purchased from that state. <u>A state should be able to take credit for renewable energy generated out-of-state as long as the state can verify that the generation has not been double-counted.</u>

A renewable energy certificate (REC) generated from an established tracking system is a viable market tool that owners/operators of affected EGU's and other 'entities' should have the option to use for the purpose of quantifying and demonstrating compliance with a renewable energy standard,

On 34922 of the proposed rule, EPA solicits comment on how to avoid double counting emission reductions as it relates to the usage of RECs and states that have implemented an RPS policy stating:

[13] News release dated May 20, 2014, *Commission Approves Wind Powered Electric Generation as Part of Georgia Power Company's Resource Mix,* http://www.psc.state.ga.us/newsinfo/NewsReleases.aspx

> *"The EPA is proposing that, for renewable energy measures, consistent with existing state RPS policies, a state could take into account all of the CO_2 emission reductions from renewable energy measures implemented by the state, whether they occur in the state or in other states. This proposed approach for RE acknowledges the existence of renewable energy certificates (REC) that allow for interstate trading of RE attributes and the fact that a given state's RPS requirements often allow for the use of qualifying RE located in another state to be used to comply with that state's RPS."*

Also on page 34922 of the proposed rule, EPA states:

> *"The agency is also proposing that states participating in multi-state plans could distribute the CO_2 emission reductions among states in the multistate area, as long as the total CO_2 emission reductions claimed are equal to the total of each state's in-state emission reductions from RE measures."*

Significant progress has been made in the voluntary RECs market since the first retail REC agreement (2000) between EPA and the Bonneville Environmental Foundation (BEF). The problem of double counting emissions reductions can be greatly minimized when RECs are properly issued and tracked. The Environmental Tracking Network of North America (ETNNA) is a voluntary association of certificate tracking systems, registries, regulators and other interested market participants that are vested in preventing double-counting and promoting harmonization among certificate tracking systems and emissions registries in North America. ETNNA has stated the following:

> *"Today, most RECs are created by a regional tracking system such as the New England Generation Information System (NE/Gis), the Pennsylvania, New Jersey and Maryland Generation Attribute Tracking System (PJM/GATS), the Energy Reliability Council of Texas (ERCOT), the Midwest Regional Tracking System (M-RETS) or the Western Renewable Energy Generation Information System (WREGIS). These are all quasi-governmental entities created to issue and track RECs of generation located within their jurisdiction. There is also a plan by the APX Company to launch a default tracking system/registry for projects located in a region not covered by the existing tracking systems. All of these tracking systems, with the exception of APX, are associated with a regional electricity reliability council and have on-going relationships with the electric utilities, balancing authorities and transmission system operators in their region."*[14]

The tracking systems described above strongly align with the acceptable Quantification, Monitoring and Verification for Renewable Energy Measures discussed in Sections V and VI of EPA's State Plan Considerations Technical Support Document (TSD); more specifically, the **REC Model** discussed on page 67 of the referenced TSD.

Furthermore, on page 34883 of the proposed rule, EPA acknowledges the significant advancements that have been made by the various REC market tracking systems stating:

[14] Page 3, ETNNA REC Questions and Answers, http://www.etnna.org/images/PDFs/ETNNA-REC-QandA.pdf

> *"Moreover, markets for renewable energy certificates, which facilitate investment in renewable energy, are <u>already well established</u> [Emphasis added]."*

<u>In summary, Georgia EPD supports the use of established REC tracking systems as a viable tool that affected EGUs, regulators, and other entities such as a public utility commission can employ to help ensure compliance with an RE standard.</u>

4. It is very important for EPA to encourage states to allow for energy efficiency (EE) savings from a wide variety of programs, including those outside of typical, certified demand side management (DSM) programs.

The fifty states represent a tremendous range of geographic, cultural, political, and climate differences. Encouraging states to count EE from a wide range of programs and policies will encourage energy savings and innovation that might not otherwise occur in individual states. It is important for EPA to recognize that participation in typical, certified DSM programs is a voluntary decision by consumers. No matter how much money is spent on marketing and outreach (and thus increasing program costs), some states and utilities simply might not be able to achieve the savings targets outlined in the CPP through typical DSM programs.

EPA states in the CPP that *"the agency does not intend to limit the types of RE and demand-side EE measures and programs that can be included in a state plan."* The Georgia Environmental Finance Authority (GEFA) and EPD encourage EPA to follow through by allowing EE savings from a wide range of programs, including those highlighted below, to count towards meeting the CPP's targets. The EPA should recognize that some of these programs are more likely to be successful in certain states, including Georgia.

Guaranteed Energy Savings Performance Contracting (GESPC).

Georgia's voters approved GESPC for state agencies in a 2010 statewide referendum. Once approved, GEFA has worked hard with stakeholders to develop a robust GESPC program that will save a significant amount of energy and money for Georgia's taxpayers. Georgia's GESPC program not only saves energy and money, but it avoids a significant amount of carbon. Georgia is on track to develop over $80 million worth of GESPCs over the next two years. By allowing GESPCs to count towards meeting the CPP, the EPA is encouraging states to grow programs that benefit both the environment and taxpayers. Because GESPCs save more than they cost, they represent a tool for states to use to achieve significant amounts of energy (and carbon) savings at no additional cost to the taxpayer.

GESPCs are especially relevant to this discussion because they are quantifiable and verifiable. Energy services companies (ESCOs) guarantee the savings and require annual evaluation, measurement and verification (EM&V). Because the savings are guaranteed and projects represent financial risk to the ESCO, the EM&V that goes into the projects is very significant.

EPA should work closely with states to determine how GESPCs can meet the goals of the CPP and ensure full credit for their related emissions reductions. In fact, states are already starting the process of evaluating how GESPCs can and should be counted for CPP compliance. The U.S. Department of Energy (DOE) awarded a State Energy Program (SEP) Competitive grant to Virginia, Kentucky, and Georgia to address this very issue. These three states will be working with each other, DOE, the National Association of State Energy Officials (NASEO), and other stakeholders to determine how GESPCs can and should be counted for CPP compliance. We request that EPA recognize this effort and work with states to ensure this project is successful thereby encouraging deployment of another EE tool.

EPA needs to also recognize that local governments represent a significant opportunity for GESPC savings. The EPA should allow for flexible and innovative systems that allow states to count GESPCs in the local government sector, in addition to state government.

Building Energy Codes

Building energy codes are a significant way for states to reduce energy consumption and emissions. Page 5 – 11 of the EPA's GHG Abatement Measures portion of the TSD states that *"state and local building energy codes can make a significant contribution"* to state EE efforts. However, the EPA also states in the CPP that building energy codes don't have the same track record of EM&V as typical utility DSM programs. It is important that EPA not use the lack of current standardized EM&V protocols for building energy codes as a reason to impede states' use of this tool in their compliance plans. EPA should work with states to develop fair and reasonable methods to account for building energy code improvements in their state implementation plans. Strong building energy codes have been an area of success for improving efficiency in many states, including Georgia. EPA should encourage continued adoption of more stringent building energy codes by helping states incorporate them into their CPP compliance plans.

Revolving Loan Funds for Energy Efficiency

Many states, including Georgia, have developed successful revolving loan fund (RLF) programs for demand-side energy efficiency. Often, as is the case in Georgia, these programs exist outside of commission regulated DSM programs and do not have rigorous EM&V standards applied to them. RLF programs are successful for a number of reasons, including low operational costs and low default rates. Importantly, they also help serve lower income residents who often do not have the needed cash or credit to make long term investments in energy efficiency, such as replacing old, inefficient, or possibly broken HVAC systems. The EPA needs to work with states to develop approvable EM&V measures that allow for energy savings to be counted in state plans. However, these EM&V programs cannot be so burdensome that they raise the operational costs of RLFs and cause utilities and states to reconsider offering them. Costs of EM&V will also often be passed along to the customers who greatly benefit from the programs. Because RLFs have dual environmental and social benefits, EPD encourages EPA to work with states to provide an easy to use framework for incorporating them into state plans.

Industrial energy efficiency programs

In Georgia and many other states, industrial customers are not part of commission certified EE programs. Due to the fact that many manufacturers compete with each other in a global market, many do not want to pay into certified DSM programs that will benefit their competitors. However, industrial customers do implement EE measures on their own. The industrial sector represents a significant amount of savings opportunity and EPA should encourage states to find ways to incorporate these savings into state plans even if they are not part of a certified DSM program.

The CPP states that it does not intend to limit the types of demand-side EE incorporated into state plans. However, if EPA does not allow for flexible, innovative, and affordable evaluation, measurement, and verification (EM&V), it will in effect limit the types of demand-side EE programs that states can incorporate into their plans. In the CPP, EPA states that it will work with federal partners to discuss the development of EM&V protocols with states in *"coming years"* (VIII, F4). If EPA does not work with states to establish acceptable EM&V protocols prior to the release of the final rule (and immediately after the release), they will limit what states can incorporate into their plans due to uncertainty. Once the final rule is released, states will have to move quickly to develop compliance programs and they will not be able to wait until *"coming years"* for EM&V guidance. It will be very hard for states to include programs such as building energy codes, appliance standards, RLFs, etc., without a clear understanding of what types of EM&V protocols EPA will accept.

EM&V also impacts the renewable energy (RE) portion of Building Block 3. Distributed generation (DG) (e.g., rooftop solar) is a growing and important way for states to incorporate more solar into their generation portfolios. In order to encourage more DG, clear, flexible, and affordable EM&V standards need to be developed with cooperation between the states and EPA.

In Section VIII. F.4 of the CPP, the EPA requests comment on whether or not they should limit consideration to *"certain well-established programs, such as those characterized in Section V.A.4.2.1 of the State Plans Consideration TSD."* EPD strongly encourages EPA to allow for a diverse array of EE programs, including those beyond typical utility or state sponsored rebate programs that are overseen by utility commissions. Building energy codes, appliance standards, RLFs, efficiency tax credits, building disclosure programs, behavioral modification programs, etc. are all successful and innovative programs that the EPA should be encouraging states to consider in CPP compliance. A one size fits all approach to EE programs does not make sense for all states, including Georgia.

The draft CPP needs further clarification beyond acceptable EE programs. A common area of misunderstanding among states, utilities, environmental advocates, etc., is whether or not savings targets specified in Building Block 4 are net or gross. Net savings targets are commonly used by public utility commissions to determine lost revenue adjustments for utilities operating DSM programs. In order to determine the actual net to gross ratio, extensive EM&V, including surveys, must be performed to adjust for issues like spill over, free ridership, etc. However, the ultimate goal of the CPP is to reduce carbon emissions from the electric power sector nationwide. Therefore, using net targets is an added and unnecessary burden on states. Gross savings is simpler to calculate and is a more appropriate methodology for both setting state goals and determining credit towards the realization of those goals. EPD requests that EPA allow for gross savings to be utilized instead of net for quantifying the carbon reduction benefit of EE programs.

5. The EPA should work with states to develop clear understanding about how interstate EE savings are handled.

A clear system needs to be developed so that Georgia gets full credit for program savings that were paid for by Georgia and implemented in Georgia. Due to the interstate nature of the electric grid, some program savings in Georgia may reduce emissions from electric generating units (EGUs) in neighboring states. It is understood that EPA wants to minimize double counting of savings, but requirements must be easy to understand and not discourage energy importing states from funding and implementing EE programs. It would not be fair for neighboring states to take credit for EE savings from programs paid for and implemented in Georgia without a clear system for reimbursing Georgia.

6. EPA needs to clarify methods of monitoring, recordkeeping and reporting. These methods should be streamlined to reduce the administrative burden on the regulated entities, states and EPA.

EPA's proposed rule does not address methods of monitoring, recordkeeping, and reporting of creditable renewable energy generation and generation avoided by energy efficiency programs; these methods must be addressed.

Monitoring, recordkeeping, and reporting requirements for state plans are presented in the proposed rule at § 60.5805, § 60.5810, and § 60.5815. However, the proposed rules appear to address only requirements for affected EGUs and make no mention of methods or requirements for renewable energy sources and programs or for energy efficiency programs. Non-emitting generation (or avoided generation) from these programs is a key component for achievement of the CO_2 emissions reductions targeted by the Clean Power Plan. As state air regulatory agencies generally have no experience with renewable energy or energy efficiency or their enforcement, it would seem very important for Subpart UUUU to provide a framework for monitoring, reporting, and recordkeeping of these affected entities. <u>Subpart UUUU must address methods of monitoring, recordkeeping, and recordkeeping of creditable renewable energy generation and generation avoided by energy efficiency programs.</u>

The recordkeeping and reporting requirements are redundant and burdensome; the duration of recordkeeping should be reduced to 5 years and the frequency of state reporting should be reduced from annual to every two years.

Recordkeeping and reporting requirements for state plans are presented in proposed rules § 60.5810 and § 60.5815. Proposed rule § 60.5810(d) requires a state to keep plan records for a minimum of 20 years. Proposed rule § 60.5815(a) requires that a state submit an annual report covering each calendar year starting in 2021. The report requires multiple data points for each affected entity in the state. Proposed rule § 60.5815(a)(2) requires the level of emissions performance for all affected EGUs for the reporting period and for <u>prior reporting periods</u>. Georgia EPD finds these requirements to be redundant and/or overly burdensome and anticipates a strain on staff resources. <u>It is recommended that the recordkeeping requirement be reduced to 5 years, which is consistent with emissions guidelines for other existing sources (e.g. 40 CFR 60 Subparts DDDD and MMMM). It is recommended that the frequency of state reporting be reduced from annual to every two years.</u>

The requirements in proposed rule § 60.5815 for reporting of emissions performance by affected entities and EGUs need clarification.

Paragraphs (a)(1) and (a)(2) of proposed rule § 60.5815 require the reporting of emissions performance by affected entities and EGUs. Georgia EPD finds these requirements confusing. It is unclear why paragraph (1) addresses requirements for *"affected entities,"* which by EPA's definition include affected EGUs, and paragraph (2) separately addresses requirements for *"affected EGUs."* Another point of confusion is that paragraph (1) requires evaluation of *"emissions performance for affected entities* *during the plan performance period and compliance periods,"* whereas paragraph (2) requires evaluation of *"emissions performance for affected EGUs during the plan performance period."* Note that proposed rule § 60.5820, Definitions, includes a definition for "compliance period" but not for "performance period." In summary, Georgia EPD requests clarification of the separate reporting requirements for emissions performance of *"affected entities"* and *"affected EGUs,"* the evaluations against emissions performance projections for different periods, and the difference between *"performance period"* and *"compliance period."*

The proposal to require the use of the most accurate RATA reference test methods for flow monitors, as expressed in Section VIII.D.9 of the preamble of the proposed rule, will unnecessarily increase costs if applied to all sources and for all tests. EPD recommends that the requirement should be changed to require only the use of the most accurate RATA reference test methods for flow monitors during initial testing.

The proposal is currently presented in Section VIII.D.9 of the preamble to the proposed rule and elaborated in the "Part 75 Monitoring and Reporting Considerations" Technical Support Document. The language is as follows:

> *"However, we are seeking comment on two possible adjustments to the Part 75 Relative Accuracy Test Audit (RATA) requirements for steam EGU stack gas flow monitors that can affect reported CO_2 emissions. The first possible adjustment would be to require use of the most accurate RATA reference method for specific stack configurations, while the second possible adjustment would be to require a computation adjustment when an EGU changes RATA reference methods. The rationale for these possible adjustments is described further in the Part 75 Monitoring and Reporting Considerations TSD available in the docket."*

The current Acid Rain Program, in 40 CFR Part 75, allows a facility to use either standard reference Test Method 2, or Test Methods 2F, 2G, 2H and CTM-041 to measure the stack gas flow rate. Test Method 2F and 2G enable the tester to measure non-axial flow or cyclonic flow more accurately. Some stacks do have significant cyclonic flow, but most do not. Test Methods 2F and 2G are much more complicated and expensive to conduct. Using these methods on stacks without cyclonic flow will not increase the accuracy of the flow measurements, but will increase the cost of conducting the test. Test Methods 2H and CTM-041 are used to measure the wall effect on circular and rectangular stacks. The velocity in a stack decays or decreases as a measuring probe approaches the wall. The velocity at the wall has to be zero. The rate of decay will be affected by the roughness of the stack wall. Test Method 2H allows a facility to use a default wall effect factor in place of actually measuring the decay near the stack wall. The use of a wall effect factor will reduce the overall net flow rate in the stack.

Georgia EPD recommends that the use of Test Methods 2F and 2G not be required for all testing. A facility should be required to conduct an initial series of tests to determine if non-axial or cyclonic flow is present and if there is a benefit to using the more accurate methods over the standard Test Method 2. If the test data supports using the more accurate test methods, then require the facility to use them for subsequent testing.

Georgia EPD also recommends that the use of Test Method 2H and CTM-041 should also be optional, as it is today.

The second proposal to require a computation adjustment when an EGU changes RATA reference test methods is not explained in either Section VIII.D.9 of the preamble of the proposed rule or in the "Part 75 Monitoring and Reporting Considerations" Technical Support Document.

The language in the TSD is shown below:

> *"Because of these flexibilities regarding use of optional reference methods used in flow RATAs, the EPA is considering two approaches to ensure consistent and accurate accounting of stack gas volumetric flow measurements. The first approach the EPA is considering is the development of adjustment factors for normalizing data when the reference methods change. For example, if a unit transitions from Method 2 to Method 2H when performing flow RATAs, a percentage reduction of baseline data could be applied."*

The language in the TSD is very similar to the language in the proposed rule. EPA needs to provide a more complete guidance document indicating how the adjustment factors will be developed and implemented.

The requirement that a state plan must include monitoring that is no less stringent than §60.5805(a)(1) to (6) is not clear. EPA should indicate in guidance if a state plan would need to include the actual monitoring plans and data, or just the monitoring requirements.

The monitoring requirements are included in proposed rule § 60.5805(a). The language is as follows:

> *"(a) A state plan must include monitoring that is no less stringent tha[n] what is described in (a)(1) through (a)(6) of this section."*

Paragraphs (a)(1) through (a)(6) specify what kind of equipment must be used and how it must be installed. They include equipment to measure CO_2 emissions, as well as electric meters. A monitoring plan is also required. There is no indication as to whether monitoring plans would need to be submitted in their entirety in the state plan for each of the affected EGUs, or if these plans could be reviewed and referenced with the appropriate Office of Regulatory Information Systems (ORIS) code and Clean Air Markets Division (CAMD) location.

The state plan monitoring requirements for measuring CO_2 emissions in § 60.5805(a)(2)(i) include a reference to Part 75 that deals with SO_2 emissions.

The monitoring requirements are included in proposed rule § 60.5805(a)(2)(i). The language is as follows:

> *"(i) An affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to §75.10(a)(3)(i) of this chapter. If an affected EGU measures CO_2 concentrations on a dry basis, they must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to §75.11(b) of this chapter."*

§ 75.11 specifies monitoring requirements for SO_2; whereas, § 75.13 specifies monitoring for CO_2. Georgia EPD recommends that the reference be changed to § 75.13.

The state plan monitoring requirements for measuring CO_2 emissions in proposed rule § 60.5805(a)(2)(ii) include a reference to Part 75 that deals with SO_2 emissions.

The monitoring requirements are included in proposed rule § 60.5805(a)(2)(ii). The language is as follows:

> *"For each monitoring system an affected EGU uses to determine the CO_2 mass emissions, they must meet the applicable certification and quality assurance procedures in §75.20 of this chapter and Appendices B and D to part 75 of this chapter."*

Appendix D to Part 75 is titled "Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units," not CO_2 mass emissions. The reference to Appendix D to Part 75 in the proposed rule should be dropped.

The state plan monitoring requirements for measuring CO_2 emissions in proposed rule § 60.5805(a)(2)(ii) include a requirement to use a laser device to measure the dimensions of each exhaust gas stack or duct. This requirement is unnecessarily burdensome and will require installing additional sampling ports that will not be used for any other purpose.

The monitoring requirements are included in proposed rule § 60.5805(a)(2)(iii). The language is as follows:

> *"An affected EGU must use a laser device to measure the dimensions of each exhaust gas stack or duct at the flow monitor and the reference method sampling locations prior to the initial setup (characterization) of the flow monitor. For circular stacks, an affected EGU must measure the diameter at three or more distinct locations and average the results. For rectangular stacks or ducts, an affected EGU must measure each dimension (i.e., depth and width) at three or more distinct locations and average the results. If the flow rate monitor or reference method sampling site is relocated, an affected EGU must repeat these measurements at the new location."*

The proposed rule requires that the affected EGU use a laser device to measure the stack dimensions at three or more distinct locations and average the results. Most large diameter stacks have four or more ports, with two ports located directly opposite from each other and perpendicular to the other set in the case of four ports. So that would only give two distinct locations, besides the fact that one would be shooting across the stack directly into the other port if they are located exactly on the same diameter. An affected EGU would have to install two or more additional sampling ports for the flow monitor and one or more sampling ports for the reference method sampling system to get measurements at three or more distinct locations. These additional sampling ports would not be used again at these locations. The requirement to measure the dimensions of circular stacks at three or more distinct locations is unnecessarily burdensome and should be removed from the proposed rules. Georgia EPD recommends that an affected EGU use existing sampling and monitoring ports to determine the stack or duct dimensions.

The state plan monitoring requirements for measuring CO_2 emissions in proposed rule § 60.5805(a)(2)(v) include a requirement to use a calibrated Type-S pitot tube when following Method 2 in Appendix A-1 to this part to perform the required RATAs of the part 75 flow rate monitoring system, and specifically not to use the default Type-S pitot tube coefficient. The proposed rule needs to specify the calibration method(s) for use on the Type-S pitot tubes.

The monitoring requirements are included in proposed rule § 60.5805(a)(2)(v). The language is as follows:

> *"If an affected EGU chooses to use Method 2 in Appendix A-1 to this part to perform the required relative accuracy test audits (RATAs) of the part 75 flow rate monitoring system, they must use a calibrated Type-S pitot tube or pitot tube assembly. An affected EGU must not use the default Type-S pitot tube coefficient."*

The proposed rule must specify the calibration method that must be used, a visual inspection procedure or a wind tunnel calibration method of calibration, and whether a standard pitot tube is acceptable. Additionally, the proposed rule needs to specify the acceptable tolerance range outside of 0.84, as no two pitot tubes have the same precise coefficient.

The state plan monitoring requirements for measuring CO_2 emissions in proposed rule § 60.5805(a)(2)(iv) include a requirement to use only the unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions. EPA should address how the CO_2 mass emissions will be affected (higher or lower) if the bias adjustment factor from Part 75 is not applied to volumetric flow rates.

The monitoring requirements are included in proposed rule § 60.5805(a)(2)(iv). The language is as follows:

> *"An affected EGU must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions from the affected facility; an affected EGU must not apply the bias adjustment factors described in section 7.6.5 of Appendix A of part 75 of this chapter to the exhaust gas flow rate data."*

The proposed rule removes the requirement in section 7.6.5 of Appendix A of Part 75 to apply a bias adjustment factor to volumetric flow rate data when the RATA test results fail the bias test. Since the CEMS CO_2 concentration data is not mentioned, the requirement to apply the bias test to the CEMS CO_2 concentration data would still be in effect under the proposed rule. EPA should provide clear technical support documentation concerning how CO_2 mass emissions will be affected (higher or lower) if the bias adjustment factor from Part 75 is not applied to volumetric flow rates.

<u>Georgia EPD believes there are opportunities to greatly simplify the monitoring, recordkeeping and reporting requirements of the CPP.</u> Tracking and reporting of carbon emissions doesn't require the same level of precision as pollutants subject to a short term NAAQS. Simplification of some of these requirements should be made in recognition of the nature of the pollutant being regulated in this rule.

7. EPA should clarify that biomass generation can be included as RE generation.

Currently, there is no clear indication from EPA on how biomass will be treated or what type of biomass will be deemed a creditable RE source. Future RE projections for the states where electric generation from biomass is included (Table 4.6. State Target RE Generation Levels of the GHG Abatement Measures TSD, page 4-22) show that projected RE targets will not be attainable within the specified time frames if electric generation from biomass is not included as RE. EPA, however, states that they *"continue to assess the framework"* while States and Stakeholders are left with uncertainty on how to move forward with biomass.

EPA includes existing or historical biomass electric generation to determine state RE targets, and simultaneously questions the continued categorization of biomass or certain type of biomass as RE. This inconsistency must be addressed. <u>Georgia EPD urges EPA to provide states with guidance concerning electricity generated from biomass in an expeditious manner and adjust state goal calculations as warranted.</u>

Georgia is also a major timber producing state. EPD encourages EPA to evaluate the potential for carbon sequestration in forests to play a role in meeting state targets and to provide guidance on how this tool could be deployed.

8. States should be able to quantify and use credits for electrification projects that result in lower carbon emissions.

Electrification projects can reduce CO_2 and criteria pollutant emissions overall. For example, the U.S. Department of Energy (DOE) states that the average plug-in electric vehicle emits much less CO_2 emissions than the same size and class conventional gasoline vehicle. See Table 6 below.

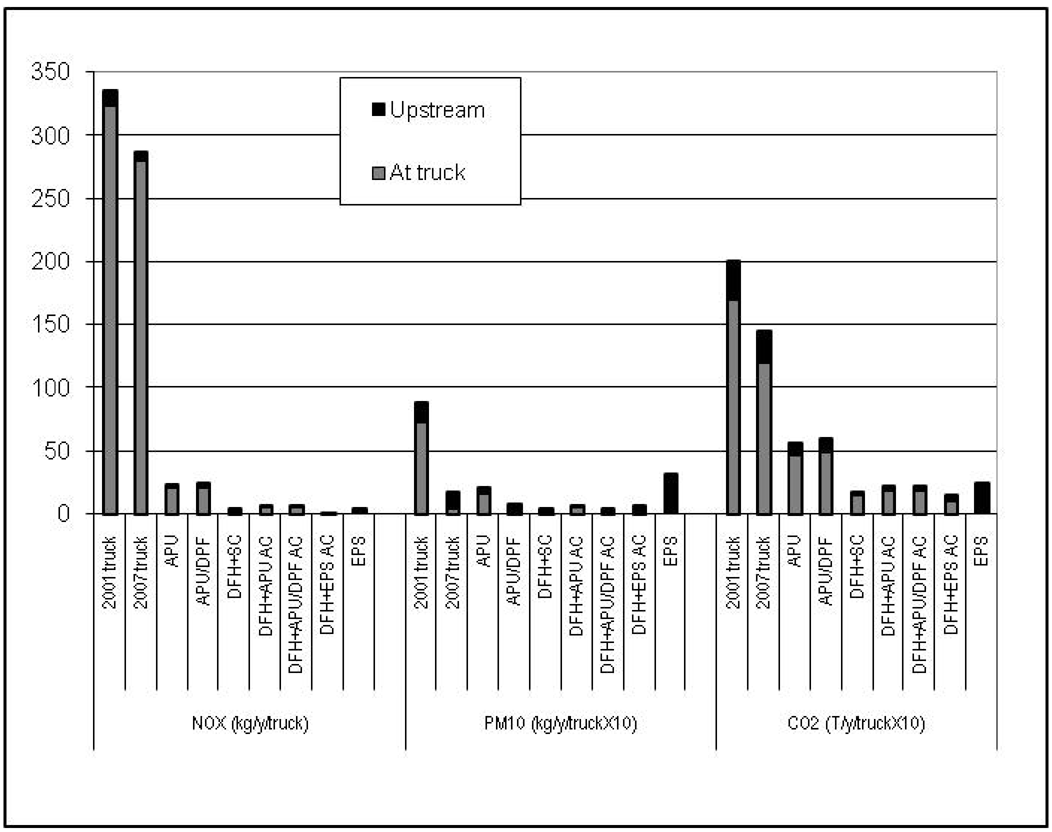
Table 6. Vehicle CO_2 Emissions for a 100-mile Trip

Vehicle (compact sedans)	Greenhouse Gas Emissions (pounds of CO_2 equivalent) per 100-Mile Trip
Conventional	**87 lb CO_2**
Hybrid Electric	**57 lb CO_2**
Plug-in Hybrid Electric	**62 lb CO_2**
All-Electric	**54 lb CO_2**

The CO_2 emissions listed in the table are "well to wheel" numbers based on an assumption that half of the grid electric power is from coal plants. The Fuel Economy Guide published jointly by the EPA and DOE consistently gives a much higher greenhouse gas (GHG) rating and fuel economy for electric vehicles (EVs) than their gasoline counterparts. For example, in the 2014 Fuel Economy Guide, the Ford Focus Electric has an equivalent combined highway/city gasoline fuel economy of 105 mpg versus the most fuel-efficient gasoline Focus, which only achieves 33 mpg. The difference between gas and electric models depends on the geographic region due to the differences in the fuel mix used for electricity generation,[15] but will only improve over time as the Clean Power Plan rules take effect. States could use their specific comparative CO_2 per mile comparison to calculate and claim CO_2 'credit' for the increased electricity usage.

Another established CO_2 benefit from electrification is shown in a DOE report titled "Energy Use and Emissions Comparison of Idling Reduction Options for Heavy-Duty Diesel Trucks." The study, published through the Argonne National Laboratory, shows that that overall CO_2 emissions are reduced with electrified parking spaces at truck stops (e.g., truck stop electrification). The report evaluated the emissions from upstream and at the truck and clearly shows an approximately 80% CO_2 benefit in idle reduction from the use of electrified parking spots (EPS) for heavy duty trucks as compared with 2001 or 2007 trucks (see Figure 2 below).

FIGURE 2. Full fuel-cycle NOx, PM10, and CO_2 emissions for nine scenarios (U.S. average)[16]



EPD is promoting electrification projects in Georgia such as electric vehicle technology and idling reduction technologies including EPS as part of our overall strategy to reduce ozone and PM2.5 emissions, particularly in the Atlanta nonattainment area. A co-benefit of these projects is that less energy is consumed and less CO_2 emissions are generated by the electric power plant to supply the

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[15] 2007, State of Charge: Electric Vehicles' Global Warming Emissions and Fuel-Cost Saving across the United States, Union of Concerned Scientists

[16] www.transportation.anl.gov/pdfs/EE/582.pdf, figure 2

electricity on a per mile basis and per hour of idling basis than running an engine on gasoline or diesel. This emission benefit will only improve as CO_2 emissions from electricity generation decreases.

Based on the amount of energy saved/CO_2 reduced, EPA should allow states to subtract CO_2 emissions from these types of programs because they reduce overall CO_2 emissions. One potential approach to crediting electrification projects would be similar to that used by the Voluntary Airport Low Emission (VALE) program offered by the Federal Aviation Administration.[17] In this program, estimates of emission reductions from projects proposed by airports applying for funding are calculated using specific methodologies published by the FAA and are submitted to the responsible air quality agency.

<u>Therefore, states should be allowed to receive credit for increased use of electric vehicles and idling reduction strategies.</u>

9. States should be able to quantify and use credits for distributed solar generation.

Distributed solar generation has the potential to be a significant source of renewable energy in Georgia by 2030. Given the time constraints of the CPP rule development, EPD has not had sufficient time to develop a methodology for tracking these projects and calculating carbon emission reductions associated with them. However, EPD thinks that a suitable method can developed that would not only allow a state to take credit for emission reductions associated with these projects but also have the effect of promoting further development of distributed solar.

<u>The final CPP rule should allow for development of a methodology for quantifying carbon reduction credits associated with distributed solar and incorporating those credits into the state plan at anytime during the interim compliance period.</u>

10. The final rule should establish an NSR accounting methodology to allow for HRI projects to be completed without triggering NSR requirements.

NSR rules will restrict large HRI projects required in Building Block 1.

On page 34928 (Section IX.A.) of the proposal, EPA recognizes that some changes to a unit's efficiency used to comply with Building Block 1 of the proposal can trigger NSR:

> "…If the emissions increase associated with the unit's changes exceeds the thresholds in the NSR regulations … including the netting analysis, the changes would trigger NSR."

EPD agrees that HRI projects required in Building Block 1 of the proposal could trigger NSR permitting. Equipment upgrades that increase efficiency can often result in *"an increase the unit's dispatch and an increase in the unit's annual emissions"* as EPA stated on page 34928 of the proposal.

The 10 major (over 500 MW) coal-fired power units in Georgia not currently slated for shutdown are all considered major PSD sources for multiple pollutants. For those plants, ensuring that the net emission

[17] http://www.faa.gov/airports/environmental/vale/

increases from a given project are not considered significant under NSR is a common way of avoiding a protracted NSR review. The plants often rely on an NSR applicability test called netting, where a facility will account for all creditable emissions increases and decreases over a 5-year contemporaneous period to determine if indeed the changes associated with a project are considered "significant" under NSR. NSR avoidance is made enforceable by limiting a units operation or utilization so that the net emission increases never exceed significant emission rates that would trigger NSR review. EPD believes that plants will be reluctant to make large capital investments in *"equipment upgrades"* as defined on page 34859 (Section VI.C.1.a.) of the proposal, if they know that the operation of the upgraded units will either be artificially limited by NSR rules or trigger requirements for additional emission controls for other pollutants. Furthermore, limiting the operation of updated units can be detrimental to efficiency if capacity factors fall below levels recommended to optimize unit heat rate efficiency. Because NSR rules will restrict large HRI projects required under Building Block 1, clear NSR avoidance strategies and options should be laid out for coal-fired units attempting to comply with a 111(d) plan.

EPD supports the expanded use of emissions reductions achieved under a 111(d) plan[18] to demonstrate compliance with NSR rules.

As a way to implement a § 111(d) plan without triggering NSR, the proposal states that:

> *"…a state plan's incorporation of expanded use of cleaner generation or demand-side measures could yield the result that units that would otherwise be projected to trigger NSR through a physical change that might result in increased dispatch would not, in fact, increase their emissions, due to reduced demand for their operation."*

On page 34928 and 34929 (Section IX.A.) of the proposal, EPA specifically seeks comment on:

> *"…whether, with adequate record support, based on underlying analysis, stating that an affected source that complies with its applicable standard would be treated as not increasing its emissions, and if so, whether such a provision would mean that, as a matter of law, the source's actions to comply with its standard would not subject the source to NSR. [EPA] also seeks comment on the level of analysis that would be required to support a state's determination that sources will not trigger NSR when complying with the state's CAA section 111(d) plan and the type of plan requirements, if any, that would need to be included in the state's plan."*

As a means of demonstrating compliance with NSR, EPD supports an approach that allows states the flexibility to:

- Estimate the amount of generation from coal-fired units that can be avoided statewide through the deployment of § 111(d) plan measures (such as heat rate improvements, demand-side energy efficiency, and expanded low-carbon and zero-carbon generation);
- Calculate the statewide emission reductions achieved from the displacement of coal-fired generation;

[18] Such as heat rate improvements, demand-side energy efficiency, and expanded low-carbon and zero-carbon generating capacity that displaces natural demand growth.

- Allocate emissions reductions to each coal-fired unit based on their generation capacity; and
- Make emissions reductions creditable for plants that wish to engage in a netting analysis to show that net emission increases will not trigger NSR review.

EPA should finalize the above approach or provide an alternative approach that clearly allows HRI projects to be completed without triggering NSR requirements.

Comments on Flexibility in State Plans

1. **Depending on the regulatory approach taken, certain aspects of the CPP could require actions by other entities in Georgia such as the PSC or legislature. The rule should allow for alternative approaches that do not require state environmental agencies to require specific actions or changes to the energy sector to achieve the 2030 goal.**

EPD does not have the regulatory authority to:

- Set state energy policy;
- Require utilities or other entities to use natural gas instead of coal to generate electric electricity;
- Require utilities to obtain electricity from renewable energy sources; or
- Require utilities to achieve energy efficiency targets.

Georgia Power is regulated by the Georgia Public Service Commission (PSC). However, the PSC has limited regulatory authority over the electric membership cooperatives (EMCs), independent power producers, and municipal utilities. The Georgia Environmental Finance Authority (GEFA), Energy Resources Division, promotes energy efficiency and renewable energy programs in Georgia. GEFA does not have the regulatory authority to mandate these programs.

In addition, the interactions and relationships of the generating units, grid managers and distribution of power are extremely complex. Environmental agencies are not equipped to effectively deal with this complexity.

One possible approach to implementing the CPP without modifying any entities' authority is as follows:

- State environmental agency could apportion the state goal (rate based or mass based) to energy generating utilities in the state (at the company level).
- A set of accounting rules would be established to set how credit for RE, EE, HRI, fuel-switching or co-firing, transmission line efficiency improvements, distributed solar, etc. would be calculated and to which entity they would accrue.
- Utilities would decide what mix of actions would be most cost effective for meeting the requirements while maintaining grid reliability.
- Intrastate trading of credits would be allowed.
- The state would track and report progress along an established glide path and each utility would have a clear compliance target to meet by 2030.

2. States should have the flexibility to choose between a rate-based and mass-based performance level for each performance period.

On pages 34908 and 34909, EPA proposed that states should have the flexibility to choose between a rate-based and mass-based performance level for each performance period. Georgia EPD agrees with this proposal. Furthermore, EPD believes that the process for switching between the forms of the goal should be simple and short. The process could be a letter notification that would accompany the last annual report for a given performance period. Consider a state that is using a rate-based goal for the 2030 – 2032 performance period. With the 2033 annual report, the state could notify EPA of its intent to switch to a mass-based goal for the performance period starting in 2033. The goals (mass- and rate-based) will have to have been determined and approved prior to such notification.

<u>EPD supports the proposal to allow states to switch between rate- and mass- based performance levels for each performance period.</u>

3. States should have the flexibility to modify their overall plan and glide path based on technology developments that may occur before 2030.

By 2030, it is inevitable that technology will evolve in ways that cannot be anticipated. Development of energy storage mechanisms, flue gas carbon removal systems, new or improved energy generation and distribution systems, advances in energy efficiency and countless other developments could have significant impact on our energy infrastructure. Historically, environmental rules have focused on regulating existing systems based on current understanding of pollution control systems and are not very effective at anticipating technology developments. The Clean Power Plan will be implemented over a 15 year or longer period in which significant changes in generation technology and energy consumption are likely to occur. The final rule should have mechanisms to allow states to adapt the requirements to these inevitable developments and avoid locking EPA, states, and the regulated entities into an ineffective or wasteful set of actions.

4. States should have the flexibility to change from a stand-alone state plan to a multi-state plan at any point during plan implementation.

States that have no experience with multi-state programs have not been able to evaluate the pros and cons of a multi-state plan in the short time allotted for CPP comments. In addition, even if a state determined that a multi-state approach made sense, the practical challenges of constructing such a program from scratch are considerable. The final rule should provide states flexibility to join an existing or form a new multi-state program at any point during plan implementation.

5. States should have the flexibility to select the 5-year Alternative State Goal.

EPD favors setting state goals that reflect a more realistic application of the building blocks. EPA's Alternative State Goal (5-year Option) approach is a step in the right direction.

Starting on page 34898 of the proposal, EPA requests comment on an alternative option with a 5-year period for compliance and a less stringent interpretation of BSER for CO_2 emission reductions. The

Alternative State Goals are listed in Table 9 of the preamble (page 34898). Table 7 below summarizes the differences between EPA's Proposal and EPA's Alternative State Goals.

Table 7: EPA's Proposed Goal for Georgia versus EPA's Alternative Goal– 5-year Compliance Deadline

Building Block	Proposed Goal	Alternative Goal
Block 1 – Heat Rate Improvements (coal-fired units)	6%	**4%**
Block 2 – Redispatch of natural gas	70% dispatch	**65% dispatch of natural gas**
Block 3a – Nuclear Under-Construction	90% of nuclear under-construction imbedded in	**No change in how nuclear under-construction is handled**
Block 3b – Existing at-risk nuclear	6% for existing nuclear imbedded in baseline and goal; baseline and goal	**No change in how existing nuclear is handled**
Block 3c – Renewable Energy	10% Renewable Energy	**7% Renewable Energy**
Block 4 – Energy Efficiency	1.5% EE per year starting in 2017 9.8% final goal in 2029	**1% EE per year, starting in 2017** **4.4% final goal in 2024**
Interim goals	2020-2029 (average) = 891 lbs CO_2/MWh	**2020-2024 (average) = 997 lbs CO_2/MWh**
Compliance Deadline	2030	**2025**
BSER Goal	864 lbs CO_2/MWh	**964 lbs CO_2/MWh**

All goal adjustments requested in this comment letter, and in the under-construction nuclear comment letter submitted by EPD on September 16, 2014, should also apply to the 5-year option.

EPD believes that the 5-year option has some merit, because it takes a slightly more realistic approach to Best System of Emission Reduction, with the very important exceptions of how EPA handles at-risk nuclear and under-construction nuclear in Building Block 3. Also, the Alternative 5-year option does not attempt to anticipate the structure of the 2030 energy sector. However, the alternative option suffers most of the same flaws as EPA's primary proposal, specifically:

- EPA's calculation methodology penalizes states with under-construction nuclear and takes away state flexibility in meeting the compliance goal, as discussed in our September 16, 2014 comment letter.
- The 5-year option requires "too much, too soon" with the interim goal, and by requiring heat rate improvements, natural gas dispatch changes and energy efficiency targets prior to the rule taking effect in 2020.

<u>EPD requests that states have the flexibility to select between EPA's proposal and 5-year option in their state plans.</u>

Comments on Other Aspects of the Proposed Rule

1. Georgia's Goal Could be Impacted by Plant Washington

Plant Washington is an 850 MW coal fired EGU proposed to be built in Washington County, Georgia. The project currently has a valid PSD permit issued by Georgia EPD. In EPA's January 8, 2014 proposed Standards of Performance (NSPS) for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units. EPA discusses various regulatory treatments of three coal fired EGU projects under development, including Plant Washington (see FR Vol. 79, No.5, page 1461). Based on our preliminary evaluation, Plant Washington, if constructed, will likely be considered a new source subject to the NSPS under the Part 60 applicability rules. However, a final determination on the NSPS regulatory status of the Plant Washington Project has not yet been made and requires further examination of detailed contractual agreements for the construction of the Project. If Plant Washington is constructed and in fact determined to be an existing source, it would be an affected unit under the 111(d) rules and, therefore, emissions from this EGU would have to be included in the baseline and goal calculations for Georgia. To address the possibility that Plant Washington might be included as an affected unit under the section 111(d) program, EPA should clarify in the final rule a process for adjusting the baseline emissions levels as well as the interim and final CO_2 emission goals for Georgia in the event that Plant Washington is constructed and determined to be an existing source.

2. The text of the actual rule should be expanded and updated to clearly address all requirements.

The text of the proposed rule is only ten pages long. Because proposed Subpart UUUU is introducing new interpretations of BSER and a number of terms and concepts that are new to air quality regulation, it is very important for the text of the rule to be clear and thorough. A number of rule requirements are either omitted or else are not addressed in a clear and thorough manner. These requirements include the following:

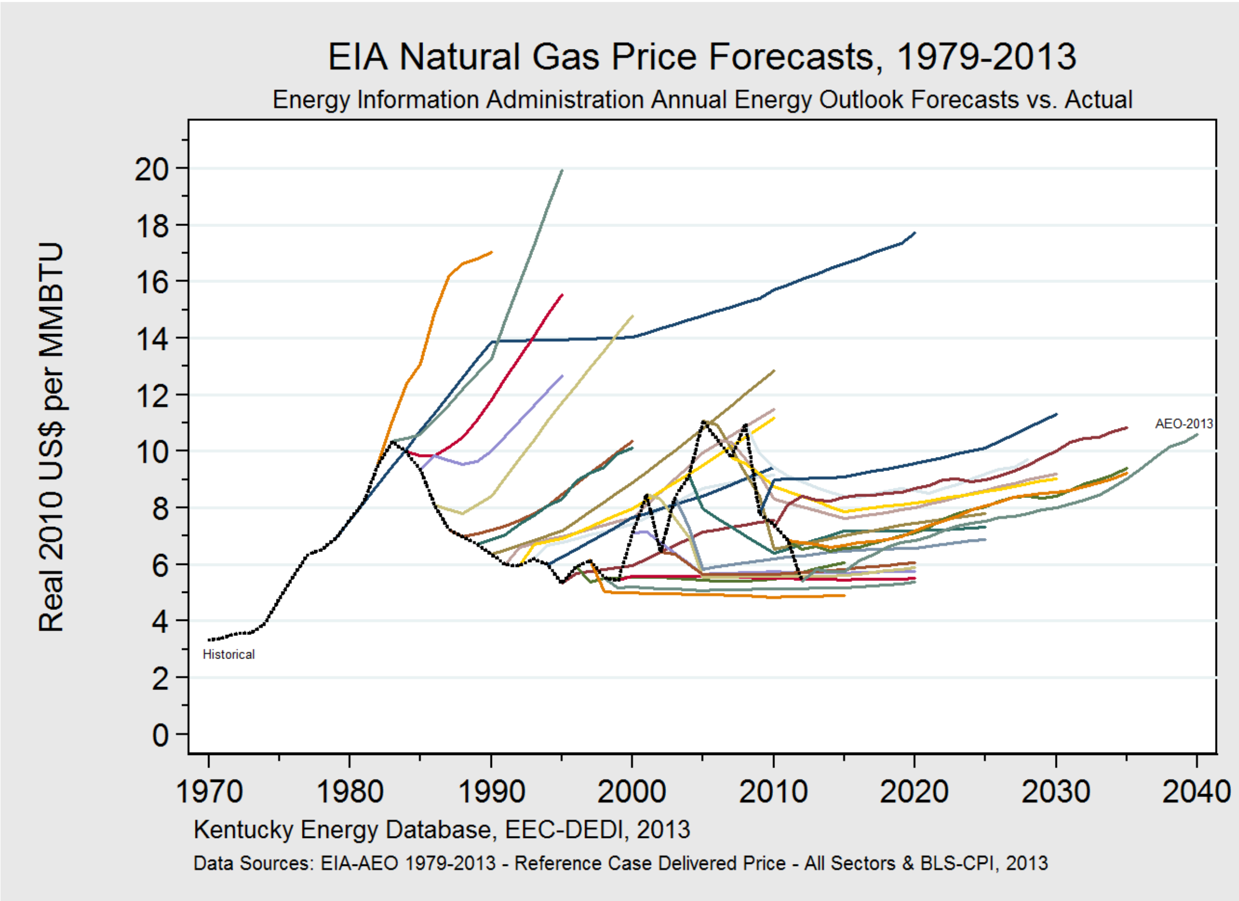
- Conversion of rate-based goal to mass-based goal
- Evaluation, measurement, and verification of renewable energy and energy efficiency
- Definition and illustration of "affected entity"
- Consistent use and differentiation of "affected entity" and "affected EGU"
- Emissions standards for affected entities

<u>Georgia EPD recommends that the text of Subpart UUUU should be expanded and revised to clearly and thoroughly address all requirements.</u>

3. There should be a safety valve mechanism in the Clean Power Plan in the event of a significant disruption in the energy markets.

The Clean Power Plan relies heavily on the assumption that natural gas will continue to be inexpensive and plentiful. Thirty percent (30%) of Georgia's CO_2 BSER reduction target is Building Block 2 natural gas re-dispatch. EPD agrees that most current projections suggest that natural gas prices will remain low for the short-term future. However, projections are just that, *projections*. Historically, projections of future energy prices (even within relatively short time periods) have been notoriously inaccurate such as the recent steep declines in natural gas prices as shown in Figure 3 below.[19]

Figure 3 – EIA Natural Gas Price Forecasts



EPD requests that EPA include in its Clean Power Plan a "safety-valve" in the event that natural gas prices rise rapidly due to some type of market disruption. For example, a large natural disaster or a significant national security issue may cause a temporary price spike in natural gas prices, or a sharp curtailment in the availability of natural gas at any price. The "safety-valve" mechanism would allow a temporary relaxation of the natural gas dispatch targets in the affected State in order to ensure grid reliability.

[19] Economic Challenges Facing Kentucky's Electricity Generation Under Greenhouse Gas Constraints, December 2013, http://eec.ky.gov/Documents/Economic%20Challenges%20Report%20FINAL%20with%20letter%2012-18b-13.pdf

4. The 6% credit for "at-risk" nuclear is insufficient incentive to keep these units in operation, and does not reflect conditions in Georgia. EPA should not include the at-risk nuclear in the goal computation.

Nuclear power plants/units are either fully operational or fully shutdown and their continued operation have been solely based on their ability to be re-licensed by the Nuclear Regulatory Commission (NRC). All of Georgia's existing nuclear units are expected to be operational throughout the compliance period of the proposed rule.

On page 34871 of the proposed rule, EPA states:

> *"Preserving the operation of at-risk nuclear capacity would likely be capable of achieving CO_2 reductions from affected EGUs at a reasonable cost. For example, retaining the estimated six percent of nuclear capacity that is at risk for retirement could support avoiding 200 to 300 million metric tons of CO_2 over an initial compliance phase-in period of ten years. According to a recent report, nuclear units may be experiencing up to a \$6/MWh shortfall in covering their operating costs with electricity sales. Assuming that such a revenue shortfall is representative of the incentive to retire at-risk nuclear capacity, one can estimate the value of offsetting the revenue loss at these at risk nuclear units to be approximately \$12 to \$17 per metric ton of CO_2. The EPA views this cost as reasonable. We therefore propose that the emission reductions supported by retaining in operation six percent of each state's historical nuclear capacity should be factored into the state goals for the respective states."*

Furthermore, on page 34858 of the proposed rule EPA states:

> *"The EPA is unaware of analogous state policies to support development of new nuclear units, but 30 states already have nuclear EGUs (with five units under construction) and the generation from these units is currently helping to avoid CO_2 emissions from fossil fuel-fired EGUs. Policies that encourage development of renewable energy capacity and discourage premature retirement of nuclear capacity could be useful elements of CO_2 reduction strategies and are consistent with current industry behavior. Costs of CO_2 reductions achievable through these policies have been estimated in a range from \$10 to \$40 per metric ton."*

Table 8 below illustrates Georgia's existing nuclear capacity along with each units' operating license expiration date. Also, based on EPA's calculation methodology, Georgia's at-risk nuclear should be estimated as: (4082MW)(8760hrs)(90% capacity factor)(6%)= 1,930,949 MWH or 220.4 MW at-risk nuclear capacity, less than EPA's estimate of 237 MW.

Table 8: Georgia's Existing Nuclear Capacity

Unit	Year Online	License Expiration	Capacity MW	Note
Hatch 1	1975	2034	924	NRC extended license 20 years in 2002
Hatch 2	1979	2038	924	NRC extended license 20 years in 2002
Vogtle 1	1987	2047	1117	Operating under original license
Vogtle 2	1989	2049	1117	Operating under original license
Totals			4082	

<u>In short, at-risk nuclear is not an issue in Georgia and EPD believes that at-risk nuclear should be removed from the emission performance goal calculation.</u>

Conclusion

EPD acknowledges that there are significant legal concerns about the structure of the CPP. However, EPD has chosen to focus our comments on the CPP on the technical and regulatory issues of the proposal in an effort to work with EPA to improve it. As proposed, the CPP does not provide sufficient state flexibility, requires significant additional CO_2 reductions prior to 2020, is unnecessarily burdensome, and fails to give credit to states that have taken early action to reduce CO_2 emissions. EPD hopes that these comments are helpful in providing a better rule than can achieve the stated goal of reducing CO2 emissions in a more equitable way, while allowing states maximum flexibility in designing their implementation approach.

Thank you for the opportunity to provide input on this important issue. Please contact me at 404-363-7016 or keith.bentley@dnr.state.ga.us if you have any questions or wish to discuss these comments.

Sincerely,

Keith M Bentley

Keith M. Bentley
Chief, Air Protection Branch
Georgia Environmental Protection Division

ATTACHMENT A –
PROJECTION OF 2030 GENERATION FOR CALCULATION OF A MASS-BASED GOAL

In the text of Georgia EPD's comment document, Table 4 presented projections of covered 2030 affected EGU and affected entity generation. These projections were used to calculate a mass-based goal for 2030. This attachment presents details as to how these projections were calculated. The table is replicated here as Table A-1 for reference.

Table A-1: Comparisons of 2030 Mass-based Goal Computations to 2005 and 2012 Actual Emissions

Method	**2030 generation basis (MWh)**	**2030 CO_2 emissions goal (tons)**	**Reduction from 94,101,000 tons (2005 CO_2 emissions)**	**Reduction from 62,850,000 tons (2012 CO_2 emissions)**
1 – rule 60.5770 basis; affected EGU generation	78,563,213 Goal Comp. TSD	32,761,000	65 %	48 %
2(a) - affected entity generation	122,216,047 Goal Comp. TSD	50,964,092	46 %	19 %
2(b) – affected entity generation	126,099,000 AEO projection	52,583,000	44 %	16 %

<u>Method 1 Generation (rule 60.5770 and Goal Computation TSD)</u>

2030 EGU generation = 78,563,213 MWh, calculated from Clean Power Plan file "20140602tsd-goal-data-computation-1.xls" which was used for the Goal Computation TSD.[20]

Source	**Cell Reference**	**Generation (MWh)**
Coal-fired, after NGCC redispatch	M12	27,190,604
NGCC, after redispatch	O12	51,372,609
Total fossil-fired		78,563,213

The 2030 EGU generation calculated above is the sum of historic (2012) coal and NGCC generation taken from file "20140602tsd-goal-data-computation-1.xls". This proxy for projected 2030 generation from existing EGUs any be reasonable since, in a reduced CO_2 regulatory environment, there is little expectation of growth in fossil-fired generation. Growth to meet increased demand is expected to come

[20] file "20140602tsd-goal-data-computation-1.xls" Goal Computation Technical Support Document, Appendix 1 – State level goals, underlying state level data, and calculations for the proposed state goals

from non-emitting sources. Note that “other generation” from EPA’s computation has been omitted for simplicity, since the “other” category represents less than 1 % of emissions and less than 1 % of generation.

<u>Method 2(a) Generation (Goal Computation TSD)</u>

2030 affected entity generation = (2030 emissions)/(834 lb/MWh) = 122,216,047 MWh . 2030 emissions is calculated from Clean Power Plan file “20140602tsd-goal-data-computation-1.xls” as shown below.

Source	Cell Reference	Emissions (lbs CO2)
Coal-fired, after NGCC redispatch	M12 x L12	58,646,790,741
NGCC, after redispatch	O12 x C12	42,213,046,893
Other	P12	68,345,447
Total		101,928,183,081

Total affected entity generation =

$$\frac{101{,}928{,}183{,}081 \text{ lbs}}{834 \text{ lbs/MWh}} = 122{,}216{,}047 \text{ MWh},$$ where 834 lbs CO_2/MWh is Georgia’s CPP rate-based goal

<u>Method 2(b) Generation (AEO 2014)</u>

2030 affected entity generation for Georgia was calculated using the total 2030 demand projection for the SERC-SE region. The data is taken from EIA’s 2014 Annual Energy Outlook (AEO) released May 7, 2014[21]. The SERC-SE region is comprised of the majority of Georgia and Alabama and small parts of Florida and Mississippi. The SERC demand growth factor is applied to Georgia’s 2012 total generation to estimate total state 2030 generation. Hydro generation and non-affected existing nuclear generation are then backed out of the total demand projection to estimate the 2030 generation from affected entities in Georgia.

Table 86 of the “Electricity and renewable fuels tables” contains the data presented in Table A-2 for the SERC-SE region.

[21] Annual Energy Outlook 2014, Release Date May 7, 2014, Electricity and Renewable Fuel Tables, Table 86. SERC Reliability Corporation / Southeastern (http://www.eia.gov/forecasts/aeo/tables_ref.cfm)

Table A-2: Generation: SERC-SE region

Generation end use	2012 generation (10^6 MWh)	2030 generation (10^6 MWh)
regional customers*	242.4	314.3
interregional exports*	24.9	31.8
international exports*	0.0	0.0
Total	267.3	346.1

*Table 86, "Net Energy for Load" data

The ratio of projected 2030 demand to 2012 demand is 346.1/267.3, which equals 1.2948. The average annual growth rate for 18 years is then 1.0144, or 1.44 %.

Total 2012 Georgia generation = 122,300,000 MWh, from EIA Georgia Electricity Profile[22]

Total projected 2030 Georgia generation = 2012 generation x 1.2948 = 158,354,000 MWh, by applying SERC-SE growth ratio

Projected 2030 affected entity generation = Total projected - 2012 nonaffected nuclear - 2012 hydro

2012 existing nuclear = 4042 MW x 8760 hrs x 0.9 cap factor = 31,867,000 MWh
2012 nonaffected nuclear (not "at risk") = existing nuclear x .942 = 30,019,000 MWh

2012 hydro = 2,236,300 MWh, from EIA Georgia Electricity Profile 2012

Projected 2030 affected entity generation = 158,354,000 - 30,019,000 - 2,236,000 = 126,099,000 MWh

Approaches To Address Deviation Of Actual Generation From Projected Final Generation Used to Calculate Equivalent Mass-based Goal

Since 2030 generation must be based on a projection or assumption more than 10 years into the future, there is a high likelihood that the actual 2030 generation will deviate from the projection. It would be advantageous to avoid situations in which the mass-based goal and the rate-based performance are not equivalent. For example, if actual 2030 generation is much lower than predicted 2030 generation, the mass emissions performance could meet the mass-based goal but the effective emissions rate performance could be higher than the rate-based goal which is "equivalent" to the mass-based goal. Since it is a given that demand will not remain constant over time, a mechanism is needed to adjust mass-based goals up or down with fluctuations in generation.

To address this issue, mass-based goals could be adjusted as the compliance year is approached. For example, consider a compliance year of 2036. In the year 2033, a state could adjust its mass-based goal

[22] U.S. Energy Information Administration, Georgia Electricity Profile 2012, Release date May 1, 2014, Table 5. Electric power industry generation by primary energy source, 1990 – 2012

with its annual report to EPA. The goal would be adjusted by using demand projection data from the 2032 AEO to forecast state electrical demand in 2036. The state's 2036 mass goal would be calculated as the product of the 2032 projected generation and the state's rate-based goal. This would become the binding annual mass-based goal for 2036 (or perhaps a 3-year period including 2036). The same process would be repeated in advance of the next compliance period after 2036.

Another approach to the deviation of actual from projected is as follows. A set of mass-based compliance goals could be generated and scaled to different hypothetical future generation levels that include and bracket the 2030 projected generation. In this way compliance of emissions performance (a mass) in the year 2030 could be evaluated against a predetermined goal in the plan that is a function of actual generation in the year 2030. In this way situations can be avoided where the mass-based goal and the rate-based performance are not equivalent. For example, if actual 2030 generation is much lower than predicted 2030 generation, the emissions could meet the mass-based goal but the effective emissions rate performance could be higher than the rate-based goal which is "equivalent" to the mass-based goal.

Consider the example presented in Table A-3. The affected entity rate-based goal is 834 lb/MWh and the average affected EGU rate is 1299 lb/MWh. Assumptions are that projected generation is 130,000,000 MWh and actual generation is 117,000,000 MWh, including 83,000,000 of fossil-fired generation.

Table A-3: Actual 2030 generation is 10% less than projection. Performance meets mass-based goal but fails rate-based goal.

2030 Parameters	Generation (MWh	Emissions (tons)	Emissions rate (lb/MWh)	Meets Goal?
Generation - projected	130,000,000			
Mass goal		54,210,000		
Total gen - actual	117,000,000			
Fossil-fired gen. - actual	83,000,000			
Non-emitting gen - actual	34,000,000			
Mass-based performance		53,908,000		Yes
Rate-based performance			922	No

The actual emissions performance meets the mass-based goal but the emissions rate performance exceeds the rate-based goal (922 versus 834 lb/MWh).

Now three generation projection bins are created to account for potential deviation of actual 2030 generation from projected generation (130,000,000 MWh):

- 110,500,000 – 123,499,999 MWh
- 123,500,000 – 136,500,000 MWh (centered on the actual projected value)
- 136,500,001 – 149,500,000 MWh

These bins and their associated mass-based goals are presented in Table A-4. The mass-based goals are calculated as the product of 834 lb/MWh and the bin midpoint generation.

Table A-4. Generation bins and associated mass goals

Generation Bin	Lower bound (MWh)	Upper bound (MWh)	Midpoint (MWh)	Mass Goal (tons)
1	110,500,000	123,499,999	117,000,000	48,789,000
2	123,500,000	136,499,999	130,000,000	54,210,000
3	136,500,000	149,499,999	143,000,000	59,631,000

In the previous example (Table A-3), actual total generation is 117,000,000, which falls into Bin 1. The mass goal for Bin 1 would be 48,789,000 tons. Using the Table A-3 generation split between fossil and non-emitting sources, the mass-based performance of 53,908,000 tons would fail the Bin 1 goal. Therefore, the generation split would have to be adjusted as shown in Table A-5.

Table A-5. Actual 2030 generation is 10% less than projection. Use reduced mass goal corresponding to Bin 1 generation range and reduce fossil generation. Performance meets mass-based goal and rate-based goal.

2030 Parameters	Generation (MWh	Emissions (tons)	Emissions rate (lb/MWh)	Meets Goal?
Generation - projected	130,000,000			
Mass goal – Bin 1		48,789,000		
Total gen - actual	117,000,000			
Fossil-fired gen. - actual	75,000,000			
Non-emitting gen - actual	42,000,000			
Emissions performance		48,712,500		Yes
Emissions rate performance			833	Yes

The actual emissions performance meets the mass-based goal and the emissions rate performance meets the rate-based goal (833 versus 834 lb/MWh). Another scenario is that actual 2030 generation is much higher than predicted 2030 generation. In this case the emissions could be higher than the mass-based goal based on the projection but the effective emissions rate performance could be lower than the rate-based goal which is “equivalent” to the mass-based goal. EPD believes that the generation bin approach described above would also address this scenario.

<u>2029 Affected Entity Generation, for Comparison to the Rate-based to Mass-based Goal Translation TSD</u>

2029 affected entity generation for Georgia was calculated using the total 2029 demand projection for the SERC-SE region. The data is taken from EIA’s 2014 Annual Energy Outlook (AEO) released May 7, 2014. The SERC-SE region is comprised of the majority of Georgia and Alabama and small parts of Florida and Mississippi. Table 86 of the “Electricity and renewable fuels tables” contains the data presented in Table A-6 for the SERC-SE region.

Table A-6: Generation: SERC-SE region

Generation end use	2012 generation (10^6 MWh)	2029 generation (10^6 MWh)
regional customers*	242.4	309.1
interregional exports*	24.9	29.0
international exports*	0.0	0.0
Total	267.3	338.1

*Table 86, "Net Energy for Load" data

The ratio of 2029 demand to 2012 demand is 338.1/267.3, which equals 1.2649. The average annual growth rate for 17 years is then 1.0139, or 1.39 %.

Total 2012 Georgia generation = 122,300,000 MWh, from AEO Georgia Electricity Profile

Total projected 2029 Georgia generation = 2012 generation x 1.2649 = 154,697,270 MWh, by applying SERC-SE growth ratio

Projected 2029 affected entity generation = Total projected - 2012 nonaffected nuclear - 2012 hydro

2012 existing nuclear = 4042 MW x 8760 hrs x 0.9 cap factor = 31,867,000 MWh
2012 nonaffected nuclear (not "at risk") = existing nuclear x .942 = 30,019,000 MWh

2012 hydro = 2,236,300 MWh, from EIA Georgia Electricity Profile 2012

Projected 2029 affected entity generation = 154,697,270 - 30,019,000 - 2,236,000 = 122,442,270 MWh