Appendix "B"

NCDENR Technical Comments

	111d Issue Category	EPA Comment Request	Fed Reg page	NCDENR Comment Response
1	Building blocks - General	As noted later in this preamble, we are seeking comment on the extent to which existing EGUs could implement carbon capture and storage (CCS) in order to improve our understanding.	34857	Implementing CCS technology for new EGUs in North Carolina was shown to be non-viable in our comments submitted on the 111(b) proposed rule. The arguments against CCS for retrofitting existing EGUs is even more compelling, given that: - CCS has not been fully demonstrated, - CCS produces large parasitic losses and requires additional energy; thereby offsetting any heat rate improvements - Additional energy requirements equates to additional air pollutant emissions from CO_2 separation, transportation, compression, and injection processes - Non-air public health related environmental impacts resulting from partial CCS were inadequately addressed, - Lack of demonstration that the proposed rule secures a balanced solution, - Absence of experience with at least one commercial scale coal-fired CCS system - Sequestration of CO_2 in large-scale geologic storage areas is not an option for NC, particularly in areas where coal-fired EGUs are located. See NCDENR 111(b) comment response letter to EPA dated May 9, 2014 for further elaboration of the above arguments.
2	Building block 1, Gas conversion or co-firing	Gas conversion or co-firing would be available to states and sources as a compliance option, and we are seeking comment on whether this option should be considered part of the Best System of Emission Reduction (BSER).	34857 Column 2	Fuel switching is not consistent with the definition of the affected source. A few studies investigated coal-to-gas conversion or co-firing gas-with-coal for EGUs to determine its long-term performance impact in terms of reliability, cost, and compliance. For EGUs like those in North Carolina that have already installed costly emission controls to meet EGU MACT standards and reduce NO_x and SO2 emissions, the gas conversion option for coal-fired units may have passed. Some study results show the feasibility that dual-fuel firing could have benefits for the flexibility to burn more of the lower cost fuel should natural gas be available at the amounts required by large EGUs. However, these studies also conclude that each boiler would have specific challenges to evaluate and overcome should it be shown that the corresponding modifications to add gas firing capability would be viable. The

				performance impact of dual-fuel firing depends not only on boiler characteristics, but also on the type(s) of control equipment installed to comply with emission control standards. Co-firing gas with coal or coal to gas conversion could increase emissions for some pollutants, prompting some form of a PSD or NSR review. EPA asks for comment whether the state plan could include a provision, 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. Even if co-firing were consistent with the definition of BSER, each unit would be required to implement a case-by-case determination, re-permitting, and PSD/NSR evaluation.
3	Building block 1, Natural gas co-firing or conversion	We already solicited comment on whether natural gas co-firing or conversion should be part of the BSER. We also request comment regarding whether, and, if so, how, we should consider the co-benefits of natural gas co-firing in making that determination.	34876 Column 1	Not all states will have adequate natural gas availability and capacity to fuel their coal-fired EGUs. Consequently, it would be a mistake for EPA to assume that co-firing is universally obtainable and practical in all cases and that any corresponding co-benefits would be available in all states. **Co-firing with natural gas or full conversion to natural gas will likely constitute redefinition of a permitted source. As such, additional permitting requirements, including PSD/NSR review would be triggered.** As an extension of Building Block 1, the co-benefits of natural gas co-firing could simply be counted by tracking net electrical generation and CO2 emissions, and calculating a composite CO2 rate on a unit or facility level. Since these units will have implemented BSER, their generation should be excluded from redispatching under Building Block 2.
4	Building block 1, Heat rate improvement at other EGU types	We are proposing that the basis for supporting the BSER should include heat rate improvements only at coal-fired steam EGUs, but we are inviting comment on including heat rate improvements at other EGU types.	34856	Heat rate improvements (HRIs) at other EGU types are available and in some cases can be cost-effective, such as equipment upgrades on NGCCs. However, EPA would need to develop a more robust justification than it did for coal EGUs in determining achievable levels for non-EGU HRI goals (see comments below on limitations and need for improvement of the proposed coal HRI goals).

				If EPA elects to allow heat rate improvements at other EGU types, it should not be included in each state's goal calculation. States should have the flexibility to treat this as an optional measure to meet Building Block 1 goal.
5	Building block 1, Heat rate improvement – use of 6%	We also solicit comment on the use of estimates up to six percent, reflecting elimination on average of 50 percent of the deviation from top-decile performance.	34860 Column 2 and 3	1. The 6% HRI reduction goal consists of two parts; 1) 4% from best management practices (BMP) and 2) 2% from equipment upgrades. The 4% BMP improvement inferred and estimated from statistical analyses on 884 units using eleven years of hourly EPA Air Markets Program Data (AMPD). After correcting for capacity factor and ambient temperature, EPA assumes that high variability in hourly heat rate values indicates opportunities for process improvement. This analysis did not include any engineering analysis of actual BMP at the top performing units. The study calculated an average heat rate of 9,753 Btu/kWh (gross generation basis) for the study population. The EPA examined 16 units that had significant year-to-year heat rate improvements. Out of these 16 units, EPA confirmed that only 2 units had made equipment upgrades to improve efficiency by 2% to 3%. EPA also cites several studies with limited actual plant data to base its BSER of 2% efficiency improvement due to equipment upgrades. These studies are used as illustrative examples and do not provide achievable coal unit efficiency improvements for today's plants to bolster EPA's reasoning. The 16 EGUs examined by EPA cover a typical, representative range of U.S. boiler characteristics in terms of capacity, age, manufacturers, firing design, and coal type. They do not, however, have emission controls suitable to meet the upcoming EGU MACT standards. Emissions controls require electricity to operate and increase the net heat rate of the unit. In addition, EPA did not report any absolute values of heat rates for the group, only the decrease in heat rate. Therefore, it is not possible for NCDENR to know what rate these units started at and if their heat rate improvements are appropriate for our units. If the units had heat rates of above 10,000 Btu/kWh and reduced their heat rate by 6%, the same improvement may not be possible on a unit already operating at 9,500 Btu/kWh or lower. The establishment of a 2% or 4% heat rate improvement requirement from

equipment upgrades for all EGUs in the U.S., regardless of current performance, is arbitrary, given the analysis presented in the rule and TSDs. Since it is not known at this time if a 2% equipment upgrade on units that are performing well below the national average is achievable, NCDENR recommends EPA provide states with possible upgrade-technologies to allow states to consider each on a case by case basis in developing their plans.

2. Since EPA did not provide the data for individual EGUs analyzed in its statistical approach, we were unable to discern where North Carolina's fleet ranked relative to others. To assess the relative performance of our coal fleet, we calculated the state-level gross heat rate using EPA AMPD data for year 2012. We found that North Carolina's 2012 gross heat rate for coal-fired EGUs was 9,071 Btu/kWh, which is significantly lower than EPA's national average of 9,753 Btu/kWh and the lowest in the country. North Carolina's heat rate performance results are before making corrections that EPA made to account for variability in meteorology and capacity factors, and would most likely be lower when these factors are accounted for. The table below shows the comparisons.

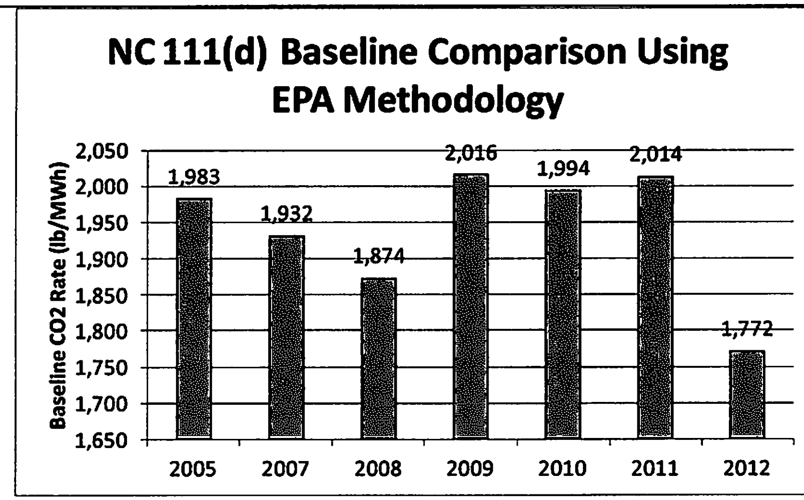
State-Level Coal-Fired Gross Heat Rate Calculated from EPA AMPD Data

State	2012	State	2012
NC	**9,071**	TN	9,878
WV	9,073	MI	9,935
DE	9,112	LA	10,041
PA	9,221	ND	10,057
OH	9,327	IL	10,086
MO	9,369	NY	10,105
OR	9,397	MN	10,126
MA	9,429	FL	10,130
UT	9,446	AL	10,135
SC	9,532	GA	10,137
KY	9,576	SD	10,163
IN	9,598	KS	10,223

NV	9,620	WY	10,275
MD	9,660	MS	10,285
NE	9,671	WI	10,287
AZ	9,742	AR	10,335
National Average	**9,753**	OK	10,350
NM	9,816	MT	10,499
IA	9,835	NJ	10,582
TX	9,836	NH	10,637
CO	9,850	WA	10,943
VA	9,862	CT	11,538

Having the lowest gross heat rate reflects that some or most of North Carolina's coal-fired EGUs have successfully implemented efficiency measures prior to the proposed rule making. North Carolina's heat rate values can be correlated with the actions taken by the state legislature with the enactment of the Clean Smokestacks Act in 2002 which required significant reductions in NOx and SO2 emissions from coal-fired EGUs. Compliance with the law resulted in multiple retirements, natural gas conversions, and add-on pollution control equipment, with 2013 being the final compliance year for meeting emissions targets.

The 2012 heat rate data presented here reflect the operating changes that occurred at the EGUs as each of the affected plants were retrofitted with NOx, SO2, and PM controls. It should be noted that in 2012, a significant shift to natural gas had already occurred, and many coal-fired EGUs were operating at much lower capacity than previous years. Despite this change, North Carolina's state-wide average heat rate remained the lowest in the nation. The figure below shows the cumulative effect of the EGU fleet change on the baseline CO2 rate. It demonstrates that North Carolina's CO2 rate declined during the recession and increased post-recession. The CO2 rate was at the lowest level in 2012 due to compliance with the CSA and a shift to lower carbon emitting fuels.



EPA's approach in the proposed rule inappropriately penalizes EGUs that are already utilizing BMP, have made equipment upgrades, and have low heat rates. The top performers have already implemented many of the cost effective BMP and equipment upgrades and would face a diminishing-return situation where further improvement options are unavailable or are more complicated and expensive. This approach is inconsistent with the statutory language of the Clean Air Act by ignoring improvements already made (North Carolina citizens have already invested $2.8 billion in coal plant pollution controls). Since North Carolina utilities are practicing a mature heat rate improvement program, efficiency enhancements on the state's coal units for heat rate should be viewed as sustaining unit performance over time. Net performance changes for a mature program can be expected to run closer to "zero".

In a 2001 study commissioned by the EPA Clean Air markets Division, it was reported that 25 best performing coal-fired plants in country had an average reported annual heat rate of 9,309 Btu/kWh. The same report cited efficiency improvements in the range of 3-5% for coal-fired power plants.

				3. In Building Block 1, EPA adjusted the state-level coal rate by reducing the "net" heat rate by 6%. In the preamble and the Technical Support Documents, EPA provides no reasonable explanation of how its analysis results on a gross basis is transferrable to net generation. As discussed below, NCDENR believes EPA has made an error by setting the goal using net generation but based the 6% HRI requirement using gross generation. This approach unfairly targets modern plants with multiple air pollution devices that consume significant parasitic and auxiliary power at the plant. The EPA study only examined heat rate as a function of gross load, not net electricity generation which is a lower number due to parasitic (auxiliary equipment) losses. EPA's heat rate BSER was based on a review of gross heat rate, and did not specifically account for variability in auxiliary power usage, especially for EGUS that operate control equipment either during ozone season or year round. During the study period, all of North Carolina's coal units operated with controls for NOX, SO2 and PM. In a 2011 study report titled "Program on Technology Innovations: Electricity Use in the Electric Sector," the Electric Power Research Institute (EPRI) concluded that on average, 7.6% of electricity produced at coal-fired power plants was consumed by on-site auxiliary equipment. Unlike EPA's evaluation, the EPRI study recognized that both gross and net generation (where auxiliary power is subtracted to quantify actual electricity supplied to the grid) must be examined to assess variations in internal power usage. By creating gross- vs. net-generation composite database from 2005-2009, the study analysis revealed that: (1) average internal power usage across the same sample size was 7.6% with a standard deviation of 2.9%, (2) internal power usage is most sensitive to plant heat rate (40%) compared to other variables such as capacity factor, duty cycle, age, and year of data – rest of the variation was noise, (3) newer plants do not appear to be most efficient because of the emission controls and associated mechanically driven cooling towers, (4) emission controls can substantially impact electricity consumption in coal power plants – applying FGD for SO2 control alone can increase auxiliary power usage from between 0.14 and 1.56%, and (5) up to 5% of power generated can be used up by air-pollution control devices.

				4. North Carolina's electric generators operate in a vertically integrated, rate-based market. In this rate-based utility structure, ratepayers will bear the cost of capital improvement costs related to equipment modifications. Utilities and state regulators may very well find that the combination of upfront capital costs to achieve these improvements for EGUs functioning as peak and intermediate operations, paired with higher electricity costs to consumers, will lead to a decision to close the plants. The loss of additional coal plants which have already shifted to natural gas dominated generation mix will likely translate to a significant economic impact to all consumers of energy, including business, in the state. In summary, NCDENR believes that EPA's approach should focus on providing candidate technologies for use by states in achieving the statutory goals under Section 111(d) rather than simply requiring percentage reductions from a particular baseline year. Because EGUs are operating at different heat rates now, requiring them to reduce by the same percentage across the board, regardless of starting circumstances, would not be consistent with the CAA. NCDENR believes that 6% reduction in heat rate improvement will most likely be unachievable universally at all coal plants or as a state-wide EGU average, especially for those plants already operating at improved efficiency levels (i.e., low heat rates), low capacity factors, and equipped with pollution controls. NCDENR recommends the EPA reconsider the following key points in its rulemaking: 1) Incorporate a multi-year averaging approach to develop a baseline (*e.g.*, 2010-2012). This approach would be more defensible since it would cover a longer time period and be less sensitive to normal variations from outages, weather, fuel costs, and dispatching. It would also allow progressive states to account for significant reductions already achieved. If EPA elects to not use a multi-year baseline approach, NCDENR recommends that EPA define a mechanism for taking credit towards meeting Building Block 1 targets.

				2) Recognize that the statutory elements for developing BSER would naturally and legally take into account the improvements already made at certain power plants. 34) Restate Building Block 1 heat rate requirement in terms of net generation instead of gross generation, and establish a heat rate threshold described in item 3 above. This approach provides the most accurate representation of efficiency ratings for coal-fired EGUs equipped with air pollution controls.
6	Building block 1, Heat rate improvement – increasing equipment upgrade to 4%	We propose to use as a data input for purposes of developing state goals an estimate that, on average across the fleet of affected EGUs, only half of the full equipment upgrade opportunity just described remains—i.e., that for the fleet of affected EGUs as a whole, the technical potential for heat rate improvements from equipment upgrades incremental to the best practices opportunity is on average 2% rather than 4%. We solicit comment on increasing this figure up to 4%.	34860 Column 3	In its analysis of equipment upgrades EPA states, "EPA expects that a significant fraction of the coal fleet has already applied some or many of the available HRI methods". As stated previously, there is no mechanism for units already meeting BSER for HRI in 2012 to be excluded from the BSER requirement or for a state to take credit for it in its plan. NCDENR recommends the proposed rule be altered significantly, as discussed previously, to allow the top-performing units to be excluded or given credit for previous efficiency upgrades. Based on the explanation provided above, NCDENR believes the establishment of a 2% or 4% heat rate improvement requirement for the state is arbitrary, inconsistent with the CAA, and based on inadequate analysis.
7	Building block 1, Heat rate improvement – increasing total to 10%	As noted earlier, we request comment on increasing the amount of heat rate improvement achievable through adoption of best practices for operation and maintenance and through equipment upgrades up to 6% and 4%, respectively, representing a total potential improvement of up to 10%, in light of the reasonable cost of HRI.	34862	Relying on statistical analysis and examining only 16 EGUs (actually 2 EGUs) to establish HRI percentages due to best practices for equipment upgrades does not truly establish BSER for existing EGUs. NCDENR recommends that prior to setting any percent improvement in heat rate from best practices or costly equipment upgrades, a more thorough analysis of achievable HRI BSER using actual EGUs is performed. NCDENR also recommends establishing a net heat rate threshold which provides a standard of performance for poorer performing units to reach without penalizing best performing units. We also do not believe that the cost of HRI at any plant should be considered reasonable, as every plant will have its own physical, operational, and economic limitations which will put a financial burden on the rate payers.

8	Building block 1, Heat rate improvement – load variability	We also solicit comment on the quantitative impacts on the net heat rates of coal-fired steam EGUs of operation at loads less than the rated maximum unit loads.	34862	EPA's regression analysis indicates that approximately "16% of the change in hourly heat rate is attributable to capacity factor and 10% to ambient temperature. These results, however, conceal considerable variability. Some EGUs, typically load-following, have an 11-year average r-squared capacity factor exceeding 50%. At those EGUs, the capacity factor is a key variable influencing changes in heat rate." The EPA was unsuccessful in identifying all the variability in its dataset, and our review of several other studies indicates that heat rate performance analysis is very complicated. For this reason, NCDENR believes a 6% requirement is unachievable everywhere and overinflates CO_2 emission reduction potentials under Building Block 1. The proposed rule provides flexibility on how a state achieves the 6% HRI and does not require that each unit meet a target gross heat rate. This allows for flexibility in unit operation as needed to provide reliability while still ensuring the base load coal units are operated efficiently. Whether these units can continue to be operated cost effectively under the proposed rule will be determined on a unit by unit case as discussed below. Since it is costly to operate a coal unit at low loads, it is assumed that some units are required to operate at low loads to ensure reliability of the electricity supply during peak load periods. These units may be capable of being tuned to have more complete combustion at lower loads. However, low load operation is still significantly inefficient compared to operating at the design load, even after tuning. It also necessitates that certain units operate at high load factors to cost-effectively improve the heat rate of the unit. However, this increase in operating load may trigger PSD/NSR permitting for certain units. Units that trigger PSD/NSR for HRI may become "stranded assets" since they cannot meet a lower CO_2 emission rate in a cost-effective manner.

				Additionally, redispatching to NGCC to 70% capacity factor could result in some coal EGUs being operated at lower loads. This would have a negative effect and increase CO2 rate for coal units because heat rate would increase.
9	Building block 1, Heat rate improvement	We invite comment on all aspects of our analyses and findings related to heat rate improvements, both as summarized here and as further discussed in the GHG Abatement Measures TSD.	34862 Column 1	Considering the issues identified in the above responses, NCDENR proposes a new methodology and time period for determining BSER for Building Block 1. This new methodology would incorporate 4 parts: 1. Establish a multiple year period (*e.g.*, 2010-2012) to define baseline conditions. 2. Examine the coal EGUs with the lowest heat rate value for <u>actual</u> BSER practices and equipment upgrades to ba applied on a case by case basis (consistent with the CAA), rather than relying on a statistical approach. 3. Use <u>net</u> heat rate rather than gross heat rate since the rule uses net electricity generation to calculate the state allowable CO2 rate. EPA needs to demonstrate through its analysis that a 6% <u>gross</u> HRI will translate directly into a 6% decrease in the CO2 emission rate of the unit. We do not believe this is a linear relationship because the CO2 rate is based on net generation. 4. Allow a state to take into consideration the statutory elements for developing BSER including the remaining useful life of an existing source to which the standard applies. The owners of an inefficient facility nearing retirement need not choose between significant modifications to continue operating for only a few years or immediate retirement. EPA should consider an option for states to treat specific facilities separately. For example, if those facilities enter into a legally enforceable agreement to retire by a certain date or compliance period, a state may not require it to take all the regulatory steps necessary to reduce its emissions to the level required at the end of that period, because the source will no longer be operating. Such a change would re-structure which units are required to implement Building Block 1, which HRI methods to implement, and the level of improvement HRIs would be required to meet and establish a true the BSER. This approach strengthens this rule by making it:

				1. More legally defensible (should it be 4%, 6%, or 10% HRI? Why is one of those values significantly less arbitrary and capricious than another?); 2. More equitable (those that already made HRIs would have less to do, those that have not made HRIs would have more to do); 3. More cost-effective (those that already made HRIs would not be forced to implement more costly HRIs, while those that have not implemented HRIs would have a list of cost effective options); and
10	Building block 1, Redispatch from higher emitting EGUs	In subsection 7, EPA seeks comment on the alternate interpretation that the BSER includes, in addition to building block 1, a component consisting of reduced generation from higher-emitting affected EGUs, with the measures in the other building blocks serving as the basis for quantifying the amounts of generation reductions and consequent CO_2 emission reductions that can be achieved while continuing to meet the demand for electricity services in a reliable and affordable manner.	34879 Column 1	NCDENR believes reducing generation from higher-emitting affected EGUs can be carried out within the fenceline of a plant, and is a viable option for achieving CO_2 emission reductions. However, consistent with our previous concerns, several North Carolina EGUs have already shifted to intermediate operations and reduced their CO_2 emissions. As such, the options for states that have taken action prior to 2012 may not have the flexibility to further reduce generation while continuing to meet the electricity demand in a reliable and affordable manner. A multi-year average should be used in conjunction with the statutory factors for developing BSER on a case by case basis..
11	Building block 1, Small rural cooperative or municipal utilities	In recognition of stakeholders' expressed concerns, we invite comment on whether there are special considerations affecting small rural cooperative or municipal utilities that might merit adjustments to this proposal, and if so, possible adjustments that should be considered.	34887 Column 2	Of the affected EGUs, NCDENR only identified one NGCC unit owned/operated by a municipality. The unit actually operates as a peaking unit and should be excluded from the rule. (See NCDENR Error Document). Therefore NCDENR does not foresee any issue with small utilities in NC unless the NGCC identified above remains in the goal calculation.

12	Building block 1, RATA requirements	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.	34913 Column 3	EPA should provide a default Part 75 volumetric flow rate adjustment factor to affected 111(d) sources but also allow sources the flexibility of conducting optional reference method tests to more accurately determine wall/angular effects on volumetric flow rate. Since the default volumetric flow rate adjustment factor will affect mass rate calculations of other pollutants, EPA should also publish supporting evidence for the default factor.

DISCLAIMER

On multiple occasions, EPA has stated that there is flexibility in the rule in that it allows states to develop their own compliance plans. These compliance plans may, but are not required to, utilize any combination of the four "building blocks" identified in the proposed Clean Power Plan. However, NCDENR is concerned that any purported flexibility is unfounded, and asks how flexibility can be achieved when EPA has already demonstrated that North Carolina will need to use all four building blocks to achieve an overall 44 percent reduction from the 2012 baseline CO_2 rate of 1772 lb/MWh to a final rate of 992 lb/MWh. It must be recognized that the proposed emission reduction goals for North Carolina cannot be achieved solely by inside-the-fence-line improvements at existing fossil fuel-fired EGUs, which is the only legal method to achieve these CO_2 emission reductions.

NCDENR believes that EPA unlawfully imposes a standard for affected, existing EGUs that is more stringent than the standard for new EGUs. Compared to North Carolina's mandatory interim goal of 1,077 lb/MWh and final goal of 992 lb/MWh, the proposed new source performance standard for a new coal unit is 1,000 – 1,050 lb/MWh and for a new gas unit is 1,100 lb/MWh. EPA's logic implies that a new fossil unit in North Carolina, which can only be constructed using the absolute best control technology, requires a far less stringent compliance requirement than existing units. There is no legal or rational basis to set North Carolina's mandatory goals for existing units below the standards required for new units. To remedy this flaw, we request that any carbon emission rate adopted for North Carolina must be higher than what is required for new units.

In order for North Carolina to meet the EPA specified final goal of 992 lb CO_2/MWh, we would need to achieve a 50% heat rate improvement or shutdown 95% of the coal generation, both of which have serious technical, cost, and energy reliability issues over the compliance period. EPA's own modeling indicates that 6,330 MW of generation will retire before 2020 in the SERV-VACAR transmission zone which includes North Carolina and South Carolina. This represents more than 30% of the 2012 capacity that EPA identifies for this zone. EPA's modeling predicts that the loss in generation will be replaced with new combined cycle, new onshore wind, new biomass, and new solar plants. NCDENR has grave concerns regarding these retirements because the power plants, with billions of dollars of investment in air pollution controls, are used today to ensure reliable service to North Carolina customers, have useful life remaining, and cannot be

replaced by 2020 without serious impacts on the electric system.

As justified in our cover letter, we believe that only heat rate efficiency improvements under the first building block is lawful under the Clean Air Act. EPA exceeds its legal authority with three of their four building blocks. EPA essentially adopts a standard that cannot be met inside the power plant fenceline, which forces states to adopt environmental dispatch, renewable portfolio standards and end-use energy efficiency standards to meet their emission targets. NCDENR strongly believes that EPA should establish BSER based on technical and economical options available to affected EGUs inside the fenceline. Having said that, NCDENR provides the following comments related to EPA's approach to Building Blocks 2-4.

13	Building block 2, Increased NGCC utilization	We invite comment on the findings regarding the potential for increased utilization of existing NGCC units to support the BSER and issues raised by the discussion and the related portions of the Greenhouse Gas Abatement Measures TSD.	34866	1. By expanding the view of the types of systems that may be considered in determining "Best System of Emission Reduction," the EPA has extended the concept of a "system of emission reduction" to include strategies and emission reduction measures that occur on-site as well as activities that occur beyond-the-fenceline of a regulated EGU. The EPA stated that because the CAA does not define the term "system", an "ordinary meaning" should be given which consists of "a set of things working together as parts of a mechanism or interconnecting network; a complex whole." EPA characterizes the electric power sector as an interconnected system and stated that the only constrains for a "system of emission reduction" is that the system reduces emissions at regulated EGUs, is the best system for doing so, and that it is adequately demonstrated. This interpretation of BSER prompted the agency to consider approaches that are made possible by the interconnected nature of the electric grid – including redispatch to natural gas. NCDENR believes EPA's alternative interpretation of the term "system" in the statutory definition is controversial and will be challenged in court. NCDENR strongly believes that the CAA limits states to define BSER within the fenceline of an affected source. Further, NCDENR requests EPA allow sufficient time for legal hurdles to clear before requiring state plans in order to conserve limited state resources.

				2. Current fuel prices are already driving the re-dispatch from coal to existing NGCC. In North Carolina, this transition occurred starting in 2010 through the beginning of 2014. We have replaced 27 coal units with large NGCC plants operating at over 60% capacity in both 2012 and 2013. These plants are newer and were designed to function as base load units. North Carolina has essentially completed most of Building Block 2 in 2014. However, EPA's selection of the 2012 base year penalizes early action states. NCDENR is are unable to take credit for pre-2012 reductions and are expected to do more than states that took no action. NCDENR requests that EPA modify its one-year, 2012 baseline reference to a three-year baseline in order to allow credit for the pre-2012 coal EGU retirements. 3. EPA should not assume that increased utilization could be exercised at non-base load units. North Carolina has two small NGCC facilities that do not operate as base load. One was operating as a peaking unit (less than 5% capacity) and the other operates at less than 15% capacity and was originally designed as a CHP plant[1]. These types of facilities may not be able to sustain an annual operating load of 70%. NCDENR requests that EPA modify the rule to exclude specific NGCC plants that operate below a specified capacity (such as 15%) on an annual and/or monthly basis and may not be able to function as base load units. The shortage of natural gas in the winter of 2014 caused some of the generation to re-dispatch back to coal. As the entire country (including utilities, industrial, commercial, and residential) moves toward using natural gas for both heat and electricity, these shortages could become more frequent and longer. It will make it very difficult to maintain 70% load year-round. NCDENR suggests that the rule include a provision for natural gas curtailment much like the National Emission Standards for Hazardous Air Pollutants (ICI Boiler MACT 5D and Area Source Boiler GACT 6J). [1]North Carolina has one older 246 MW NGCC facility that historically operates as a peaking facility, Butler-Warner Generation Plant (ORIS ID 1016) which is owned/operated by Fayetteville PWC. This facility has a capacity factor of

				less than 3% annually and less than 15% during peak use months. This facility, and others like it, cannot be not operated at 70% load. NCDENR requests that EPA modify the rule to exclude NGCC plants that operate below a specified capacity (such as 5%) on an annual and/or monthly basis. This will correct the North Carolina's NGCC capacity that is available for utilization at 70% load. ***Please see attachment titled "Errors in EPA's Proposed 111(d) Guidelines Related to North Carolina" for additional comments.
14	Building block 2, Proposed 70% capacity factor for NGCC	We invite comment on whether we should consider options for a target utilization rate for existing NGCC units greater than the proposed 70 percent target utilization rate. We invite comment on these proposed findings and on all other issues raised by the discussion above and the related portions of the Greenhouse Gas Abatement Measures TSD.	34866 Column 2	For the reasons cited earlier regarding natural gas availability and potential for price escalation, NCDENR does not believe it is reasonable for EPA to consider a higher natural gas utilization rate. Anything higher than 70% puts states at risk for meeting their goals if there is a period of NG curtailment. It may cause a short-term spike in the cost and availability of natural gas if all states move to 70% capacity at relatively the same time. It might be better to have a ramp up period.
15	Building block 2, New NGCC capacity	EPA invites comment on whether we should consider construction and use of new NGCC capacity as part of the basis supporting the BSER. Further, we take comment on ways to define appropriate state-level goals based on consideration of new NGCC capacity.	34877 Column 1	According to the proposal rule, new units would not be required to comply with state plans. However, EPA proposes that any existing units that are modified or reconstructed after becoming subject to approved implementation plans issued under the proposed 111(d) rule would continue to be subject to the plan's CO2 reduction requirements. These units would be required to comply with both the state plan's applicable section 111(d) requirements and the separate federal NSPS for modified/reconstructed units. EPA states that existing facilities could eliminate 111(d) implementation plan simply through modification. EPA proposes to codify all of the proposed rule's requirements for all affected sources into a single source category under a new subpart UUUU (40 CFR part 60), citing that a single super-category for all fossil EGUs would facilitate emission trading among sources. It appears that EPA is combining the gas and fossil-fueled EGU categories as a legal prerequisite for treating redispatch from coal-fired to gas-fired EGUs as a component of BSER.

				Including new NGCC units as part of BSER for existing units is complicated from a legal standpoint. They are already subject to 111(b) and "outside the fence line" of the existing units. While we understand EPA's desire to propose a cost-effective rule that maintains reliability of the electric supply, this approach is not defensible. NCDENR fears that EPA's proposed action could create regulatory uncertainty when it is challenged in court. States would be placed in a predicament with having to comply with a plan, while at the same time the very basis of that compliance requirement would be uncertain. We request EPA to incorporate additional time into the compliance schedule for such legal issues to be resolved so that limited state resources would not be wasted.
16	Building block 2, Method for counting new NGCC generation towards BSER	The agency requests comment on how emissions changes under a rate-based plan resulting from substitution of generation by new NGCC for generation by affected EGUs should be calculated toward a required emission performance level for affected EGUs.	34924 Column 1	See comments 13-15 from above. NCDENR recommends the EPA's emissions guidelines provide for a state budget approach option for only existing sources being regulated for CO_2 under a Section 111(d) program. This is because new affected sources will be regulated under Section 111(b) through the New Source Performance Standards (NSPS), which, as proposed, establish unit-specific CO_2 limits.
17	Building block 1 & 2, Best System of Emission Reduction (and inside-the-fence)	We are also soliciting comment on application of only the first two building blocks as the basis for the BSER, while noting that application of only the first two building blocks achieves fewer CO_2 reductions at a higher cost. In this system, emission reductions at the most carbon-intensive individual affected EGUs would occur through a combination of heat rate improvements (resulting in a decrease in emission rates) and substitution of generation at less carbon-intensive affected EGUs, notably existing NGCC units. One reason for considering a BSER comprising these two building	34836 Column 3 34878 Column 2 34885 Column 1	See comments 13-16 from above. We offer the following additional comments. 1. Emissions guidelines mandating an electric grid system-based approach (i.e., the re-dispatch of EGUs based on a lower CO_2 emission rate) should not be part of a 111(d) program. This type of program could disrupt the competitive energy market and could place EGUs at risk of early retirement, resulting in potential grid reliability issues. The dispatch of EGUs is beyond the scope of the EPA's authority, and the regulation of carbon dioxide emissions is beyond the authority of Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs). The operation of a competitive energy market is the role of RTOs and ISOs while the regulation of environmental pollution in a state is the responsibility of the state/local air agencies. 2. Any physical change or change in the method of operation relating to

		blocks is that it involves only affected EGUs and generation from affected EGUs.		efficiency improvements at an affected facility would trigger NSR applicability determinations. If NSR is triggered, the owner or operator may opt out of such efficiency improvement projects or choose not to optimize or maximize the benefits of the project, which is counter to the intent of the emissions guidelines. Therefore, NCDENR recommends that for purposes of GHGs, NSR regulations for EGUs be amended to redefine major modification as a modification that increases any regulated air pollutant emissions in terms of the lbs/MWh, rather than the current threshold of tons per year. There are likely other provisions in the CAA that have "absurd results" when it is used to regulate CO2 or other greenhouse gases. Consistent with the CAA, those provisions should all be identified and "tailored" to provide for the greatest opportunity to avoid unintended or negative consequences should this program for EGUs be implemented under Section 111(d) of the CAA.
18	Building block 1 & 2, Regional or state scenarios given greater weight	We invite comment on whether the regional or state scenarios should be given greater weight in establishing the appropriate degree of re-dispatch to incorporate into the state goals for CO2 emission reductions, and in assessing costs.	34865 Column 3	If EPA chooses to finalize the 111(d) rule by including Building Block 2 and it is sustained after legal review , NCDENR agrees with giving states flexibility to establish their own redispatch options. However, by EPA setting the goals at 6% heat rate improvement and 70% NGCC capacity, the states' options may be limited because EPA's proposal changes the current electricity dispatch process which considers cost and reliability to adding environmental factors.
19	Building block 1 & 2, Averaging times for emission standards	In its proposed 111(b) rules for new EGUs, EPA proposed that the appropriate averaging time for an emission standard for new EGUs be no longer than 12 months. Similarly, the EPA proposes here that an appropriate averaging time for any rate-based emission standard for affected EGUs and/or other affected entities subject to a state plan is no longer than 12 months within a plan performance period and no longer than three years for a mass-based standard. We also solicit comment on longer and shorter averaging times for	34913 Column 1	A 12-month averaging period for rate-based emission standards is consistent and doable with the Clean Air Markets and the Federal Energy Regulatory Commission data reporting. The issue of averaging times is not critical for GHG emission standards relative to any GHG environmental impact.

		emission standards included in a state plan.		
20	Building block 2, CHP useful thermal output credit method	Consistent with the requests for comment in the proposed CAA section 111(b) GHG NSPS regulations for modified and reconstructed sources, we invite comment here on a range of two-thirds to 100 percent credit for useful thermal output in the final rule, or other alternatives to better align incentives with avoided emissions.	34914 Column 1	NCDENR does not believe that the thermal contribution of CHP should be relied upon in the plan to meet a state goal since it requires that the thermal output be used far into the future. An agreement to generate heat for a co-located industrial or manufacturing facility may not last though the interim period, 2030, and beyond. Using the short term agreements to establish BSER puts states at risk of not meeting their carbon rate reduction goals. NCDENR does not think thermal energy generation with CHP systems should be included in baseline calculations. NCDENR does believe that increased thermal efficiency offered by CHP systems can be best utilized as an incentive for a state or EGU to reduce its carbon rate as a compliance option. For facilities and states that want to add CHP capacity due to captive market needs, NCDENR believes EPA should require reporting of both electric and useful thermal output (e.g., lb steam generated). In these cases, full 100% credit for useful thermal output should be allowed. ***Please see attachment titled "Errors in EPA's Proposed 111(d) Guidelines Related to North Carolina" for additional comments.
21	Building block 1 & 2, Net versus gross energy output and proposed protocols	We solicit comment on whether EGUs producing both electric energy output and useful thermal output should be required to report both electric and useful thermal output. In addition, the proposed protocols would allow facilities to use alternative apportionment procedures with EPA approval. We invite comment on the proposal for reporting of net rather than gross energy output and on the proposed protocols.	34914 Column 1	Consistent with the above comment, CHP should only report net electric generation. Relying on thermal generation as part of the baseline calculations will put states at risk due to the short term nature of CHP agreements. If a state chooses to use CHP activities as part of its state compliance option, a CHP facility should be given credit for any reduction in CO_2 from the thermal portion but it should not be part of BSER since it is difficult to enforce and is not permanent. ***NCDENR has identified errors in EPA's calculation of useful thermal output. Please see attachment titled "Errors in EPA's Proposed 111(d) Guidelines Related to North Carolina" for additional comments.

	111d Issue Category	EPA Comment Request	Fed Reg page	NCDENR Comment Response
22	Building block 3, RE generation targets	17. For some states, the RE generation targets developed using the proposed approach are less than those states' reported RE generation amounts for 2012. We invite comment on whether the approach for quantifying the RE generation component of each state's goal should be modified to include a floor based on reported 2012 RE generation in that state.	34868 Column 1	*As stated previously, NCDENR believes the application of Building Blocks 2 through 4 is not legally defensible, as proposed. Notwithstanding our objections to legality of the Proposed Rule, we offer the following comments, corrections, and questions regarding the substance of the Proposed Rule.* Establishing a floor for states with large amounts of existing RE which they cannot go below seems arbitrary when there is no floor that states with little or no RE must achieve. This would penalize forward thinking states for their existing accomplishments in lowering EGU CO2 rates. NCDENR does not support a floor for maintaining existing RE levels. The proposed rule should not use RE to derive at state's goals. Instead, as discussed earlier, a state's final CO2 rate should be based on achievable and realistic CO2 reductions at the effected EGUs. RE should only be used as a means to achieve that goal, giving states the flexibility to move between building blocks as they see fit to meet their goals to minimize cost and maintain reliability of electric generation. Under the current plan, some states are required to generate large amounts of RE while others are required to generate less than 5%. Who will bear the cost for this approach? States that happen to be sunny or windy will be disproportionately affected. We understand this was done because it offered "achievable, cost effective" reductions in CO2, but it places a much greater burden on specific states. If EPA establishes a state's final goal by including RE, we believe that all states should have to contribute equally or by a minimum amount (see our comments on the Alternative Path Forward). For establishing BSER for states with little or no existing RE, NCDENR proposes requiring each state to meet either 1) a minimum level of RE generation in units of MWh instead of percent of 2012 generation or 2) a state-specific target based on the state's own technical and economic evaluation of RE potential. For example, KY only has to generate 1.7 million MWh of RE of the required 9.0 million MWh (less than 20%) by 2030 using EPA's proposed approach. Other states in the region are required to meet all 10% of the regional target because they started with higher RE generation in 2012. If a floor is established, Kentucky and other low RE generation states would be required to generate a minimum level if they will not meet the target generation by 2030. Alternatively,

				state's like North Carolina which established its Renewable Energy and Energy Efficiency Portfolio Standard (REPS) based on what is technically achievable, should be allowed to adopt the REPS as the standard under Building Block 3.
23	Building block 3, Alternative RE method	We invite comment on the alternative approach to quantification of RE generation to support the BSER described on pages 34869-70. We note that the three specific requests for comment addressing, 1. the possibility of a floor based on 2012 RE generation, 2. the possibility of a limitation based on 2012 fossil fuel-fired generation, and 3. the treatment of hydropower generation	34870	*As stated previously, NCDENR believes the application of Building Blocks 2 through 4 is not legally defensible, as proposed. Notwithstanding our objections to legality of the Proposed Rule, we offer the following comments, corrections, and questions regarding the substance of the Proposed Rule.* 1. NCDENR favors creating a floor for RE, a minimum level of RE required by each state, rather than a percentage of <u>existing</u> RE generation. Given the disparity in RE investment among the states this is a more fair approach and establishes a true BSER. 2. Establishing BSER from implementation of RE based on a state's existing fossil fuel generation is arbitrary. NCDENR does not recommend this approach. NCDENR recommends that to the extent Building Block 3 is determined to be a legal application of BSER, each state assess its own RE potential using appropriate technical and economic analysis to develop state-specific goals that are cost effective and practical. In North Carolina's case, the state's REPS represents the product of this analysis and the resulting RE target of 3.75% be used as the standard for North Carolina. 3. North Carolina allows for hydropower to be used to comply with our REPS rule. Historical values for hydropower are approximately 3.6% of all RE generated in the state from NC RETS tracking system. Inclusion of new hydropower in BSER calculations for North Carolina needs to reflect this level.
24	Building block 3, RE capacity	We invite comment on this approach to treatment of renewable generating capacity as a basis for the best system of emission reduction adequately demonstrated and for quantification of state goals.	34869 Column 3	*As stated previously, NCDENR believes the application of Building Blocks 2 through 4 is not legally defensible, as proposed. Notwithstanding our objections to legality of the Proposed Rule, we offer the following comments, corrections, and questions regarding the substance of the Proposed Rule.* One of the biggest flaws of the approach to RE as BSER in the proposed rule is inclusion of wood biomass in the 2012 Baseline and the calculated average regional growth target. EPA has not established at this time if biomass electric generation is "carbon neutral" or not, even in light of EPA's release of a second

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draft of the Framework/or Assessing Biogenic C02 Emissions from Stationary Sources and corresponding memo's.

Using EIA data, NCDENR determined seventeen states have over <u>one third</u> of their RE generated by wood as shown in the table below. If future EPA rulemaking determines that a portion of this wood is not carbon neutral or allows some fraction of the CO2 emitted as a pollutant, it would drastically impact the achievable RE in many states. Until this decision is made, EPA cannot include baseline generation from wood to establish RE growth rates and future generation targets. EPA must remove wood generation from 2012 RE generation for each state, and recalculate everything for the affected states.
<table>
<tr><th>State</th><th>Wood and Wood Derived Fuels</th><th>Total Generation</th><th>Total RE Generation</th><th>Percent RE from Total</th><th>Percent of Wood from Total RE</th></tr>
<tr><td>AL</td><td>2,768,765</td><td>152,878,688</td><td>2,776,554</td><td>2%</td><td>100%</td></tr>
<tr><td>MS</td><td>1,492,749</td><td>54,584,295</td><td>1,509,190</td><td>3%</td><td>99%</td></tr>
<tr><td>LA</td><td>2,366,281</td><td>103,407,706</td><td>2,430,042</td><td>2%</td><td>97%</td></tr>
<tr><td>AR</td><td>1,589,891</td><td>65,005,678</td><td>1,660,370</td><td>3%</td><td>96%</td></tr>
<tr><td>GA</td><td>3,107,494</td><td>122,306,364</td><td>3,278,536</td><td>3%</td><td>95%</td></tr>
<tr><td>SC</td><td>1,940,953</td><td>96,755,682</td><td>2,143,473</td><td>2%</td><td>91%</td></tr>
<tr><td>TN</td><td>714,577</td><td>77,724,264</td><td>836,458</td><td>1%</td><td>85%</td></tr>
<tr><td>NC</td><td>2,262,087</td><td>116,681,763</td><td>2,703,919</td><td>2%</td><td>84%</td></tr>
<tr><td>NH</td><td>1,035,295</td><td>19,264,435</td><td>1,381,285</td><td>7%</td><td>75%</td></tr>
<tr><td>ME</td><td>2,944,950</td><td>14,428,596</td><td>4,098,795</td><td>28%</td><td>72%</td></tr>
<tr><td>KY</td><td>236,543</td><td>89,949,689</td><td>332,879</td><td>0.4%</td><td>71%</td></tr>
<tr><td>VT</td><td>327,561</td><td>6,569,670</td><td>465,169</td><td>7%</td><td>70%</td></tr>
<tr><td>VA</td><td>1,435,790</td><td>70,739,235</td><td>2,358,444</td><td>3%</td><td>61%</td></tr>
<tr><td>FL</td><td>2,057,561</td><td>221,096,136</td><td>4,523,798</td><td>2%</td><td>45%</td></tr>
<tr><td>MI</td><td>1,697,524</td><td>108,166,078</td><td>3,785,439</td><td>3%</td><td>45%</td></tr>
<tr><td>MA</td><td>658,991</td><td>36,198,122</td><td>1,843,419</td><td>5%</td><td>36%</td></tr>
<tr><td>WI</td><td>1,148,874</td><td>63,742,910</td><td>3,223,178</td><td>5%</td><td>36%</td></tr>
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<tr><td>25</td><td>Building block 3, RE alternative approach</td><td>EPA is soliciting comment on an alternative approach to quantification of renewable generation to support the BSER. The alternative methodology relies on a state-by-state assessment of RE</td><td>34869 Column 3</td><td>As stated previously, NCDENR believes the application of Building Blocks 2 through 4 is not legally defensible, as proposed. Notwithstanding our objections to legality of the Proposed Rule, we offer the following comments, corrections, and questions regarding the substance of the Proposed Rule.</td></tr>
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technical and market potential.

Under this alternative RE approach, EPA would quantify RE generation for each technology in each state as the lesser of (1) that technology's benchmark rate multiplied by the technology's in-state technical potential, or (2) the IPM-modeled market potential for that specific technology. For example, if the benchmark RE development rate for solar generation is determined to be 12%, and this hypothetical state has a solar generation technical potential of 5,000 MWh/year, then the benchmark RE development level of generation would be 600 MWh/year. If the IPM-modeled market potential for solar generation in that state is 750 MWh/year, then this approach would quantify solar generation for that state as the benchmark RE development level (600 MWh/year) because it is the lesser amount of those two measures. This alternative RE approach is one example. EPA invites comment on other possible techno-economic approaches.

The EPA invites comment on other possible techno-economic approaches to quantification of RE generation to support the BSER. For example, a conceptual framework for another techno-economic approach is provided in the Alternative RE Approach TSD.

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EPA's alternate methodology which relies on state specific RE technical and market potential appears more plausible than the proposed approach discussed earlier. In North Carolina's case, the benchmark approach requires a 5% RE generation by 2030, which is much more in line with the North Carolina Utilities Commission's estimate of 3.75% RE generation in 2020 due to implementation of North Carolina's existing REPS.

North Carolina's 2030 Reductions from Implementation of Various RE Scenarios in the proposed rule are as follows:

RE Implementation Options	% of 2012	2030 Avoided Generation (MWh)
EPA Proposed BSER	10%	13,918,901
EPA Alternative -Tech Potential	5%	6,211,000

Many questions still remain regarding EPA's alternative approach, including:

- Why did EPA use the average development rate of top 16 states to identify benchmark development rate for each state? Why not use top 10 or top 20?
- If EPA justifies using top performing states to establish an RE benchmark, why not use the same approach in other parts of the rule? One example is to specify an average heat rate (Building Block 1) using the most efficient fossil fuel fleet and establish a benchmark heat rate improvement target for all states based on actual best performing units.
- Why is all biomass counted as a renewable resource when EPA has not issued a final ruling on its GHG contribution and its second draft framework states only sustainable or waste feedstock biofuel is carbon neutral?

The alternative approach includes an increase in hydropower of 85,224 GWh in 2030 and for the U.S, a 31% increase. The proposed RE BSER assumes no increase in hydropower due to limited potential and variability although states can include it as an option. Since hydropower is 45% of the existing RE in this country, NCDENR recommends that U.S. EPA solidify its position on whether or not hydropower can actually be expanded and included in the computation of BSER. Note that NC REPS allows for use of hydropower projects but an increase of 13% is substantial and probably not realistic in our state. As stated above,

				historical values for hydropower are approximately 3.6% of all RE generated in the state from NC RTES tracking system. Note that EPA <u>did not include</u> "biomass renewables" in their analysis of the alternative but <u>did include</u> it in their proposed BSER goal calculation (See earlier comments and discussion in error document submitted by NCDENR). Therefore, it is difficult for NCDENR to comment on the application of biomass in this alternative since it is different from the proposed BSER for RE. EPA must finalize its position on whether or not various types of biomass are considered carbon neutral. It must then determine the amount of biomass fuel used for electric generation is derived from sustainable or waster feedstocks. Then, it must carry that policy forward in its analysis of both the proposed goal and any alternatives which are presented for comment.

Generation in GWh	Solar	Onshore Wind	Biopower	Geothermal	Hydropower
EIA U.S. 2012 Generation	4,317	140,299	19,823	15,301	273,441
U.S. 2030 Target Generation	8,722	384,826	28,777	16,516	358,665
U.S. % Increase from 2012	102%	174%	45%	8%	31%
NC 2012 Generation	139	-	302		3,728
NC Alternative Target 2030	371	184	1,430		4,226
NC % Increase from 2012	166%	N/A	373%		13%

26	Building block 3, RE capacity	This RE approach does not account fossil fuel-fired generation in each state. *The application of this approach could yield, for a given state, an increase in RE generation that exceeds the state's reported 2012 fossil fuel-fired generation.* The EPA invites comment on whether the approach for quantifying the RE generation component of each state's goal should be modified so that the difference between a state's RE generation target and its 2012 level of	34868-69	*As stated previously, NCDENR believes the application of Building Blocks 2 through 4 is not legally defensible, as proposed. Notwithstanding our objections to legality of the Proposed Rule, we offer the following comments, corrections, and questions regarding the substance of the Proposed Rule.* Washington FF generation in 2012 = 9 million MWh RE in 2029 = 17 million MWh This problem only occurs for Washington where only 8% of the generation comes from fossil fuels (9 million MWh) and 89 million MWh comes from hydroelectric. In this case, EPA's approach for BSER for Washington's fossil fuel plants requires that Washington generate an additional 9.8 million MWh from

		corresponding RE generation does not exceed the state's reported 2012 fossil fuel-fired generation.		RE, more than their 2012 fossil fuel generation. This BSER approach is clearly not fair considering that the seven states with the least 2012 investment in RE generation (MD, TN, CT, KY, DE, RI, AK) have a 2029 <u>combined</u> RE target that is less than Washington's target in 2029 of 17 million MWh. Creating a plan where all states share equally the cost of investing in appropriate RE, from both a technical and economic perspective is crucial.
27	Building block 3, RE capacity with and without hydropower	With regard to hydropower, we seek comment regarding whether to include 2012 hydropower generation from each state in that state's "best practices" RE quantified under the proposed approach, and whether and how the EPA should consider year-to-year variability in hydropower generation if such generation is included in the RE targets quantified as part of BSER. Chapter 4 of the GHG Abatement Measures TSD presents state RE targets both with and without the inclusion of each state's 2012 hydropower generation.	34869	*As stated previously, NCDENR believes the application of Building Blocks 2 through 4 is not legally defensible, as proposed. Notwithstanding our objections to legality of the Proposed Rule, we offer the following comments, corrections, and questions regarding the substance of the Proposed Rule.* *Hydropower represents 7% of the nation's 2012 generation. Almost all states have implemented some hydro. As EPA states in its TSD, hydropower is not expected to grow substantially due to the lack of new large-scale resources.* NCDENR agrees with EPA that new large-scale hydropower does not represent a BSER for existing coal. In addition, NCDENR agrees that any new hydropower projects or uprating any existing hydropower should be given credit for emissions reductions under the rule. Inclusion of hydropower in the goal calculation assumes that hydropower is kept constant; therefore, it does not impact calculation of the state goal. However, it will impact <u>achieving</u> the goal if hydroelectric generation drops below the 2012 baseline value due to weather conditions. Therefore, keeping existing hydropower out of the state goal calculation does not penalize states in the event of an extreme weather event. NCDENR recommends this approach Regarding variability, this issue will also impact other sources of RE to some degree. How would a state "enforce" the required target generation from a solar or wind project every year? A state would have to build in substantial margin of RE generation to protect from weather events impacting the generation of solar/wind farms across the entire state in order to ensure meeting the annual state goal. An averaging mechanism over a three year period might protect a state from a required enforcement action on an RE source.

<table>
<tr><td>28</td><td>Building block 4, Alternative energy efficiency savings</td><td>As discussed in Section VII.E below, the EPA is also taking comment on a less stringent alternative for setting state goals: including using 1.0% instead of 1.5% annual incremental savings as BSER</td><td>34873 Column 2</td><td rowspan="2"> As stated previously, NCDENR believes the application of Building Blocks 2 through 4 is not legally defensible, as proposed. Notwithstanding our objections to legality of the Proposed Rule, we offer the following comments, corrections, and questions regarding the substance of the Proposed Rule. NCDENR offers the following comments regarding the application of EE in the range of 1% to 2% annually as BSER under Building Block 4. 1) The Abatement Measures TSD states “For states with lower levels of current performance (and, hence, later achievement of the best practices level of performance – as late as 2025 in some instances), this requires sustaining the target level for as little as five years. For states currently at or above the best practices level of performance, this reflects an ability to sustain the target level for thirteen years (2017 through 2030).” Under the current rule, states that have already implemented many of the basic EE programs are required to achieve EE savings. North Carolina electric utilities have actively developed EE programs under the incentives provided in REPS. Despite this flexibility, the past six years of historical EE implementation shows that a 1.5% annual incremental rate and a 10.3% annual cumulative rate by 2030 are unrealistic for North Carolina. The most recent Integrated Resource Plans filed by North Carolina utilities indicate EE savings in 2030 of 0.9%, 4.3% and 6.5% for Dominion North Carolina Power, Duke Energy Progress, and Duke Energy Carolinas, respectively. We believe that after the basic, cost effective EE measures are implemented, the remaining measures are more difficult to implement due to higher capital costs for equipment replacement. States with no existing EE in 2012 can implement more cost-effective EE measures to meet their reduction goals. While many other building blocks are difficult to achieve due to cost considerations, <u>EE is the one building block that all states can achieve equally</u>. NCDENR recommends that EPA modify the proposed BSER for EE such that each state must meet a minimum level of <u>cumulative rate of reduction</u> from 2012 to 2030 regardless of the current level of EE savings in 2012. This approach gives </td></tr>
<tr><td>29</td><td>Building block 4, Alternative numerical values and approaches for energy efficiency</td><td>For demand-side EE, we also specifically invite comment on several issues:
(1) Increasing the annual incremental savings rate to 2.0 percent and the pace of improvement to 0.25 percent per year to reflect an estimate of the additional electricity savings achievable from state policies not reflected in the 1.5 percent rate and the 0.20 percent per year pace of improvement, such as building energy codes and state appliance standards,</td><td>34875</td></tr>
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				credit to states that have taken early action to reduce electricity consumption and does not burden them with higher EE program costs than states that took no action. <u>We also request that states' with existing REPS policies may utilize the target established in such policies to establish BSER for their state under Building Block 4.</u> This approach was discussed further in the error document submitted by NCDENR. **2)** In 2012, North Carolina *RETS* System, the state tracking system employed for both RE generation and EE savings, reported <u>annual</u> EE savings of 1,269,063 MWh, which is <u>0.97% of 2011 electricity sales</u>. This is larger than what is allowable under the REPS rule, 0.75%. However, under the NC REPS rule, EE savings in excess of the allowable can be <u>banked</u> for use in the future, when EE gets more difficult and costly to implement. NCDENR requests that EPA examine a system of banking (and trading) for EE similar to what was implemented by the North Carolina Utilities Commission. This system is called NC RETS and approaches MWh of avoided generation in a similar fashion to RECs. This may give states additional flexibility in complying with the rule in a cost effective manner. In addition, early action states with EE programs in place between 2012 and 2016 should be allowed to bank EE savings achieved prior to the rule effective date, assuming the EE savings meet certain Evaluation Measurement and Verification (EM&V) requirements. 3) For the reasons cited above, NCDENR believes that increasing the annual incremental savings rate to 2.0 percent and the pace of improvement to 0.25 percent per year is unnecessary if all states are required to implement a minimum target level of EE measures by 2030. Furthermore, any additional EE savings that a state wants to take credit for can be based on technical and economic factors affecting that state (i.e., based on REPS requirement).
30	Building block 4, Estimating demand-side energy efficiency	We invite comment on all aspects of our data and methodology for estimating the potential for demand-side energy efficiency to support the BSER as discussed in the preamble and in the TSD, as well as on the level of reductions we	34875	*As stated previously, NCDENR believes the application of Building Blocks 2 through 4 is not legally defensible, as proposed. Notwithstanding our objections to legality of the Proposed Rule, we offer the following comments, corrections, and questions regarding the substance of the Proposed Rule.* NCDENR offers the following comments regarding EM&V requirements in the

	savings	propose to define as best practices suitable for representation consistent with the best system of emission reduction and the level reflected in the less stringent scenario.		Abatement and State Plan TSDs. In the state plan section, the rule states it will require a rigorous EM&V approach for estimating avoided generation due to RE projects and EE programs. However, EPA does not propose specific EM&V requirements with this rule. Then, a footnote on page 5-13 of the GHG Abatement TSD states "[173] *The "EM&V" box is not comparable to the other program types and is not relevant to this discussion. It was included in the referenced source to indicate that EM&V is a key activity within a program portfolio*. From these statements in the State Plan and Abatement TSDs it appears that the technical requirements and the costs for EM&V were not specifically addressed by EPA. EM&V for each MWh of EE and/or RE is a costly and time consuming process and, in some states such as NC, requires third party verification. Since meeting EM&V requirements under this rule may require a great deal of time and money, NCDENR recommends that prior to establishing the final requirements of the rule, EPA must specify EM&V elements that state plans must address. In addition, NCDENR requests that EPA estimate the costs associated with meeting the specified EM&V requirements for both EE and RE and include them in the BSER cost benefit analysis.
31	Building block 4, Alternative energy efficiency savings	For demand-side EE, we also specifically invite comment on several issues: (2) alternative approaches and/or data sources (i.e., other than EIA Form 861) for **determining each state's current level of annual incremental electricity savings**, and (3) alternative approaches and/or data sources **for evaluating costs** associated with implementation of state demand-side energy efficiency policies.	34876 Column 1	*As stated previously, NCDENR believes the application of Building Blocks 2 through 4 is not legally defensible, as proposed. Notwithstanding our objections to legality of the Proposed Rule, we offer the following comments, corrections, and questions regarding the substance of the Proposed Rule.* NCDENR offers the following comments regarding sources of EE savings and cost data. 1) Available Sources of EE Savings Data There are various sources for EE data. It is generally reported on a program by program basis. It is reported as both incremental and cumulative, depending on the data source. 1. North Carolina requires extensive EM&V of each MWh of electricity generated using RE or avoided generation using EE. Each MWh must be certified by a third party prior to the credit being issued. The RE and EE data is reported, tracked, banked and retired using NC RETS, our tracking system for RE and EE under REPS. 2. The utilities and service providers must compile the data for submission to

the NCUC for an annual report. This report is now part of the IRP for the major utilities in NC. The NCUC reviews the submitted data and compiles a report for the public.

3. In order for the service providers and utilities to recover costs associated with EE and RE, the RE and EE generation data, along with the associated cost data, is reported, reviewed and approved through the NCUC docket system. It allows for public review, comment and intervention in establishing the cost recovery riders for each EE program established by the utilities and service providers. Each EE program operated by the service providers has its own docket where the data is reported and reviewed.

The table below presents the 2012 EE Savings reported to EIA on Form 861 and what was reported to NC RETS by electricity service providers to comply with the REPS rule, which requires EM&V for each MWh of EE savings.

2012 NC RETS Data	1,269,063 MWh	0.97% of 2011 Sales
2012 EIA Form 861 Data	470,285 MWh	0.40% of 2011 Sales

We do not know why there is a large discrepancy between the two data sources. It does point out the difficulty of tracking EE savings data in a reliable manner. Using EIA Form 861 data to establish state-specific BSER from EE, when EPA acknowledges that the data is not complete/reliable, is not a legal determination of BSER for each state.

2) Alternative Approaches for Evaluating Costs

It is not clear that the cost of the rigorous EM&V and reporting requirements associated with tracking EE savings were included in the costs for this BSER. The Abatement TSD does not present costs at the level of detail required to make this assessment. EPA must include costs associated with specific EM&V requirements in its analysis of BSER (see previous comment on EM&V).

North Carolina utilities are allowed to increase rates in order to offset the costs to implement EE programs required under our REPS rule. Large consumers of electricity were allowed to opt out of the EE rebate program because of the possibility of a rate increase. All major electricity consumers in North Carolina

				opted out because of the uncertainty of rate increases. NCDENR recommends that any cost study related to EE measures should include an analysis of rate hikes for residential and commercial customers. In addition, any measures adopted by states to encourage voluntary participation of commercial/industrial customers in EE programs should address uncertainty in rates.
32	Building block 4, Imported electricity	47. With respect to building block 4, we specifically invite comment on the alternative in Step 5 of **scaling up the estimated reduction in the generation by affected EGUs in net electricity exporting states** to reflect an expectation that a portion of the generation avoided in conjunction with the demand-side energy efficiency efforts of other, net electricity-importing states would occur at those EGUs, analogous to the proposed adjustment for net electricity importing states described in Step 5. We also request comment on the alternative of making no adjustment in Step 5 for either **net electricity-importing or net electricity-exporting states.** These alternatives are discussed in the Goal Computation TSD.	34897 Column 1	*As stated previously, NCDENR believes application of Building Blocks 2 through 4 is not legally defensible, as proposed.* NCDENR offers the following brief discussion below on net import/export related issues. See our comments on the State Plan for a more comprehensive discussion of this allocation issue for both EE and RE. *REPS and EE policies in most states tie existing reduction goals for RE and EE to <u>sales</u> rather than <u>generation</u>, for good reasons. EPA has attempted to tie these EE savings back to generation in order to calculate appropriate BSER goals for each State. EPA asks for comment on the following adjustments to EE savings in each state when calculating BSER goals:* *1) decreasing state EE BSER goal by % of electricity imported (proposed method),* *2) decreasing importing state EE BSER goal by % of electricity imported and then increasing exporting states BSER goal by this amount,* *3) do not adjust goals for importing/exporting.* 1) Fifteen states import electricity in the US. In 2012 North Carolina imported approximately 18% of its electricity. For importer states, EPA adjusts EE savings requirement in Building Block 4 by the import amount which seems like a reasonable approach. However, NCDENR does not believe that our generation will actually decrease by this amount. EPA AVERT model runs indicate that most of the avoided generation from EE and RE will take place outside of North Carolina. Imported electricity is more expensive and will be one of the first resources to be displaced. EIA 2013 data confirms this assumption since our imports went down from 18% in 2012 to 9% in 2013. This drop in imports may be due in part to our existing EE programs. 2) Allowing a state to only take credit for in-state CO2 reductions occurring as a result of EE programs creates a <u>disincentive</u> for importing states. As discussed previously, electricity imports are generally more expensive and this resource will be displaced first before displacement occurs within the state's own sources.

				As an importing state, North Carolina EGUs may never achieve a reduction in generation because as additional EE measures are implemented, the EE savings would simply come off the electricity imported to the state. If EPA establishes the same cumulative percent reduction goal in 2030 for each state, EPA may be able to avoid adjusting goals for importing and exporting states. For instance, if all states must cumulatively reduce electricity sales by 10% by 2030, all states would be reducing GHG emissions at power plants fairly from an end user standpoint. States that import electricity would have to share in the cost of reducing GHGs from EGUs located in other states. This type of CO_2 reduction would not have to be accounted for in the state reduction goals as lbs/MWh. It could be implemented more like the <u>best management practices</u> under the boiler MACT, which requires tune-ups and energy assessments. This proposed process could still require EM&V and tracking to ensure actual savings are achieved. This approach would make the cost to reduce CO_2 emissions from EE fair to all states regardless of whether they are importing or exporting. It simplifies calculating BSER goals for each state. Lastly, it simplifies tracking of EE and does not require complex negotiations between states to account for importing/exporting and avoided generation. If states wanted to implement additional EE reductions beyond those required by best practices, the additional savings could be counted as avoided generation in a state carbon emissions rate. See comments for state plan for further discussion of this issue. 3) EPA asks if states that are exporters, whether they should have to <u>scale up</u> the EE savings to establish BSER in order to ensure all EE is included in BSER goals. This methodology requires that the remaining MWh of avoided generation due to EE be allocated to the various states from which North Carolina imports. Using this approach to calculate BSER goals, which are <u>fixed</u> once the rule is promulgated, assumes that all states will maintain the same in terms of their import/export relationships through 2030. Given the changes in generation, costs, and usage that may develop as a result of this significant rule making, this assumption appears highly inaccurate. If EPA adopts such a methodology, NCDENR recommends <u>providing a mechanism for correcting state CO_2 rate goals if the import/export allocations between states change significantly</u>.

33	Building block 4, Multistate accounting methods	EPA is seeking comment on the options summarized below, as well as alternatives. These options and alternatives, and how they might apply to both projections of plan performance and reporting of achieved plan performance, are addressed in the State Plan Considerations TSD. **1.** The EPA is proposing that, for **demand-side EE measures,** consistent with the approach that the EPA used in determining the BSER, a state could take into account in its plan <u>only those CO2 emission reductions occurring in the state</u> that result from demand-side EE measures implemented in the state. **2.** The agency is also proposing that, for states that participate in **multi-state plans,** the participating states would have the flexibility to <u>distribute the CO2 emission reductions among states in the multistate area</u>, as long as the total CO2 emission reductions claimed are equal to the total of each state's in-state emissions reductions that result from demand-side EE measures implemented in those states. **3.** We are also proposing that states could jointly demonstrate CO2 emission performance by affected EGUs through a multi-state plan in a **contiguous electric grid region**, in which case attribution of emission reductions from demand-side EE measures would not be necessary. We also request comment on whether a state should be able to take credit for emission reductions out of state due to in-state EE measures if the state can demonstrate that the reductions will not be double counted when the relevant states report on their achieved plan	34921 Column 3 34922	*As stated previously, NCDENR believes application of Building Blocks 2 through 4 is not legally defensible, as proposed.* NCDENR offers the following comments on all aspects of EPA's EE and RE approach. One general comment is there are so many approaches to calculating these emissions and how to take credit for them in a state plan that it is overwhelming to comment on them, especially for state air quality agencies that have not been actively involved in CO2 reduction programs or REPS. **I. Quantifying and Allocating Avoided Emissions for RE and EE Measures** NCDENR offers the following comments on the proposed methods for estimating and allocating in-state/out of state CO2 emissions reductions due to avoided generation from RE and EE measures. Some insight into the complexities of the proposed methods for importing states is also presented. **1. Need for a national RE/EE Tracking System** There are already private and government entities throughout the U.S. that provide services to verify, track, and bank the generation plus the environmental and social attributes associated with the RE generation. These market places have established rules for inter-state trading of generation and credits. Under most RPS rules, the RE generation can take place in other states. Tracking is done to avoid double counting of RE. As discussed earlier in NCDENR's comments for Building Block 4, North Carolina has an established entity which verifies, tracks, and banks <u>both RE generation and EE avoided generation</u> for its RPS. EPA merely needs to build on these concepts to provide verification, tracking, and banking of both RE generation and EE avoided generation in MWh at the national level. A unified system of requirements will allow for tracking and trading between states. **2. Determining Avoided Generation and Avoided Emissions** The alternative to a banking/tracking system is to require modeling of EE savings to establish where the avoided generation is most likely to occur. <u>Knowing the location of the EGU</u> where generation is avoided is <u>not</u> required under most RPS programs. Verifying where the avoided generation actually occurs and who gets

		performance, and what such a demonstration should entail. We request comment on these and other approaches for taking into account CO2 emission reductions from demand-side EE measures in state plans. We invite comment on all aspects of the proposed form of the goals.	34895	to take credit for CO2 reductions under EPA's proposed rule is a significantly more complex problem. The following section comments on EPA's proposed methods. *EPA proposes three methods for estimating the location of CO2 reductions and for* ***quantifying CO2 emissions reductions*** *due to avoided generation resulting from EE and RE measures; A) EPA's EGRID method which uses the average CO2 rate for an electricity grid region to simply decrease theCO2 emissions reductions by the percent of electricity imported or exported , B) AVERT model which is a simple dispatching model that estimates expected decreases in generation at the county level, and C) energy sector modeling tools such as IPM, a complicated and proprietary hourly electricity dispatch model that can forecast specific marginal units expected to reduce generation. AVERT and IPM can estimate emission reductions from the units which are most likely to go offline (marginal units), while EGRID merely estimates emission reductions using a fleet average emissions rate. Both of these models are not appropriate due to limitation in short term forecasting capability and EGRID factors are usually 2 years older than the most current year.* Employing Method A to quantify and allocate emissions reductions greatly oversimplifies electricity dispatching, where importing states may not even see in-state generation displacement, and could easily double count emissions reductions. Due to its simplicity, it is not appropriate to calculate <u>verifiable</u> reductions in the state-wide CO2 emissions rate as part of a BSER requirement. There is no mechanism to ensure the reductions are not being double counted. Method B, the EPA AVERT model, uses a more rigorous approach. It is relatively simple to use and does not require a great deal of resources to use. State air quality planners can understand and use the model. It has three primary drawbacks. First, it does not provide forecasting beyond five years. This limits a state's ability to make long term assessments and agreements with states required for multistate plan development. Second, it assumes that dispatching in the future will be similar to the recent past. The proposed rule will probably result in substantial changes to electricity dispatching. Therefore, this model may not support planning beyond a few years. Lastly, it requires coordinating

				with all the other states in the electric grid region to estimate the expected reduction in MWhs and the hourly load profile for those MWhs in the reporting/planning period. Note some states have their EGU fleets divided between two or more grid regions so these states are required to perform estimation and allocations of CO2 reductions for planning/reporting for multiple grid regions. This is a daunting requirement, and based on our state's experience with other regional air quality programs, the complexities and unknowns associated with the Carbon Plan will create tremendous barriers to overcome. Method C, IPM or other electricity forecasting model, provides a robust approach which allows for examining changes to the dispatching (including peak units), energy cost, etc,. While it solves the issue of allowing more robust forecasting, it requires a significant investment of state resources due to the complexities of the model; including obtaining avoided MWhs from each state as well as, time consuming, complicated and expensive for a given state to utilize. NCDENR believes this approach has two major drawbacks; 1) it requires significant amount of time to coordinate and QA the data collection for annual planning and reporting, and 2) its complexity requires coordination and execution of the modeling for the entire U.S. by EPA or a third party (given that IPM is a proprietary model). We also believe that EPA is not equipped to provide the necessary assistance to states as it took EPA more than two years to release the latest NEEDS database for state's review and has yet to release the final version of 2018 IPM runs and emissions modeling platform. EPA also discusses other state-wide or regional electricity dispatch models, many of these models are proprietary, complex and unknown to state regulators. NCDENR does not see how these complicated models can be used by states for plan development without significant resources and cooperation on the part of states, EPA, utility commissions, and utilities, and electricity modelers. If EPA is going to require modeling for both <u>annual</u> plans and progress reports, this methodology will impose a huge burden on the states. At the end of the day, we must keep in mind that these are just statistical models and cannot be used to <u>verify</u> where electricity generation is actually reduced without error. EPA even makes the following statements in the TSD.

"Marginal units change on a moment-to-moment basis, determined by load requirements and the variable cost of each unit available to generate another unit of power"

"The magnitude of the EE/RE program and the EE/RE load impact shape is a key element in determining marginal emissions reductions."

In summary, we believe the modeling approach is very complex and states do not have the tools to accurately characterize state-level and regional electricity dispatching characteristics. Tracking avoided generation at the plant level due to EE and RE action in another state would require a system capable of modeling the integrated electricity grid at a regional or national level. We believe this challenge is analogous to interstate transport modeling required for the eastern U.S. to address ozone contributions from neighboring states. EPA discusses the different type of energy models in the Proposed Rule that could be utilized; however, this discussion is superfluous and does not provide an appropriate tool to accomplish the task. Individual states simply do not have the methods, resources, and expertise to engage in energy modeling. EPA's approach can only be utilized if an appropriate, non-proprietary and accurate model is available for state's use.

3. Incorporation of Emission Reductions into a State Plan

Allowing a state to only take credit for in-state CO2 reductions due to RE and EE unfairly treats states which import electricity. In 2012 North Carolina imported approximately 18% of its electricity. We have an existing REPS rule which requires implementation of RE and EE. NCDENR recognizes that only a small portion of the reductions impact in-state generation. Imported electricity is more expensive and will be one of the first resources to be displaced. This assumption is confirmed as given below.

1) Per EIA 2013 data, North Carolina's electricity imports went down from 18% in 2012 to 9% in 2013. This significant drop in imports is assumed primarily due to the existing RE and EE programs.

2) AVERT modeling of EPA's projected 2030 cumulative EE and RE impacts to

				generation was performed by NCDENR. EPA's AVERT model predicts that <u>only 5%</u> of the avoided generation from North Carolina EE and RE programs <u>will actually occur in North Carolina (see data tables below)</u>. The results indicate that most of the avoided generation from EE and RE will take place outside of North Carolina. The remainder of the avoided generation was spread out among the southeast states. The largest percentage reduction was in Florida, a state that is reported to have transmission constraints. The modeling results are presented in tables given below.

North Carolina's Cumulative RE & EE Avoided Generation in 2030
Per EPA Proposed Rule
Data Used as Input to AVERT

Year 2030	GWh
RE Generation	13,918
EE Avoided Generation	14,130
Total	**28,048**

Results from AVERT Modeling
(assumes both RE and EE impact base load generation)

State	Annual Gross Generation, Post-EERE (MWh)	Annual Displaced Generation (MWh)	Annual Displaced CO2 (tons)	% Displaced by State from Regional Displacement	% Reduction from State Gross Generation
FL	161,407,200	-6,007,600	-3,503,100	22%	-4%
AL	91,547,000	-3,388,400	-2,083,400	12%	-4%
KY	84,913,400	-2,244,700	-2,064,400	11%	-3%
GA	79,048,600	-3,551,000	-2,449,600	11%	-4%
NC	**56,922,700**	**-2,690,800**	**-2,142,800**	**8%**	**-5%**
LA	48,781,500	-845,100	-575,900	7%	-2%
TN	38,378,600	-1,270,400	-982,200	5%	-3%
AR	36,879,100	-1,436,500	-1,008,000	5%	-4%
VA	36,006,800	-1,954,800	-1,162,900	5%	-5%
SC	33,765,700	-1,121,000	-911,700	5%	-3%
MS	29,899,200	-1,689,400	-979,600	4%	-6%
TX	19,592,600	-700,900	-346,100	3%	-4%

MO	17,610,800	-435,900	-374,700	2%	-2%
WV	9,327,200	-387,000	-379,100	1%	-4%
OK	2,382,000	-288,500	-121,600	0.3%	-12%
Grand Total	**746,462,400**	**-28,012,000**	**-19,085,100**	**100%**	

Allowing a state to only take credit for in-state CO2 reductions occurring as a result of RE generation/EE measures creates a disincentive for implementing these building blocks within states that import electricity. If the proposed rule is not revised, net importing states will not be able to achieve the required in-state CO2 reductions under BB3 and BB4.

4. Joint Demonstrations and Multi-State Approaches

EPA proposes 4 different methods for ***incorporating the emissions reductions into the statewide CO2 emissions rate.*** *These include;*

1) *Allowing a state to take into account only CO2 emission reductions occurring in its state from RE/EE.*
2) *State credit for emission reductions out of state due to RE/EE if the state can demonstrate that the reductions will not be double-counted by relevant states in their CO2 rate, and what demonstration should entail.*
3) *Joint demonstration by states on CO2 reductions at affected EGUs through a multi-state plan in an contiguous electric grid region, in which case state allocation of emission reductions from RE/EE is not necessary.*
4) *For multi-state plans, the participating states could distribute the CO2 emission reductions among states in the multistate area, as long as the total CO2 emission reductions claimed are equal to the total of each participating state's in-state emissions reductions.*

EPA's proposed approach of requiring a state to determine where the avoided generation has/will occur and only giving credit for in-state reductions is going to be burdensome to states in terms of planning, record keeping, and ensuring no double counting. For each MWh of avoided generation, North Carolina must prove where the electricity did not come from and then come to an agreement with that state such that the other state does not take CO2 credit for North

				Carolina's actions. NCDENR does not have any control over where the avoided generation takes place, any way to prove this in a court of law, and no means to compel a state to give up the emission reduction credit so that North Carolina citizens, who paid for the reduction measure, can utilize it in a state plan. Implementation of this building block in a state plan will require very high level negotiations between many states and energy generators on an annual basis, potentially. Therefore, NCDENR does not recommend implementation of EPA's proposed Building Block 3 and Building Block 4 (RE and EE) using a multi-state approach due to the burden of the legal requirements, the multi-state planning and negotiating requirements, and the record keeping/modeling requirements. At a minimum, EPA needs to examine how to handle the tracking of avoided generation to prevent double counting where the EE/RE is paid for by one state, implemented by a second state, and the generation is avoided in a third state. It needs to provide the states with a more concrete methodology for this accounting/modeling, a nation-wide reporting system, and third party verification of which unit avoided generation due to EE/RE in which state. A <u>third party approach</u> is the only way to prevent legal issues between states and utilities. **5. Reductions at Non-Affected Units** EPA states that emissions reductions will potentially occur at peaking and new EGUs which are <u>non-affected units</u> under the rule. New units are less likely to go off line because they generally are efficient and therefore lower cost to operate. However, new units may impact which marginal EGUs go online/offline differently than were forecasted. In turn, these phenomena may impact the forecasted in-state reductions and the state's ability to meet its expected reductions. Emission reductions will definitely occur at peaking units, which are not affected units under the rule. States will be investing enormous amounts of resources in emission reductions from these two building blocks and get very little credit toward CO2 rate reductions at affected units

Conclusions

NCDENR believes that requiring states to include avoided emissions in its calculation of the state-wide CO2 emission rate required to demonstrate compliance with EPA's BSER state goal has many issues including;

- It requires significant state resources including, time, manpower, and costs.
- It is an overly complicated compliance demonstration given the uncertainty in the actual emissions reductions, in regards to both quantity and location.
- It requires difficult and time-critical coordination and negotiations between multiple states and
- It creates large legal issues for states.
- States that pay for expensive RE installations may get little or no actual reduction in their CO2 rate
- Peaking units, which are not affected units under the rule, may be impacted more than the affected EGU population.
- Since state government has no control or authority over EGU dispatch, is the state at fault if the CO2 reductions in our state do not occur as planned/estimated by these models, especially in light of any significant changes in generation, energy supply issues, or other unforeseen events?

II. Alternate Path Forward

If EPA proceeds with a rule that includes illegal beyond-the-fence requirements, EPA should modify the rule such that the RE and EE building blocks are simplified to alleviate the emissions tracking and multi-state issues that were discussed above.

One approach would be to require each state to meet the same cumulative percent reduction in 2030 for EE and RE measures based on electricity sales.

By basing RE and EE reductions on a percentage of sales, the impact of importing and exporting of electricity is inherently accounted for and states share the burden appropriately on a cost/use basis. The CO2 reductions will occur across the entire U.S. at the units which are least efficient and have higher operating costs. These units are more likely to be the older, higher emitting units. Therefore, the overall CO2 emissions rate for all the states would be lowered.

				This could be implemented much like the Boiler MACT and GACT best management practices, which require tune-ups and energy assessments. This type of CO_2 reduction would not have to be accounted for in the state reduction goals as lbs/MWh. Tracking the location of avoided generation would not be required on such a rigorous basis. The RE generation and EE avoided generation could maintain the same EM&V and reporting to ensure the energy savings actually occur. EPA could then be responsible for modeling of EGU CO_2 emission rates periodically to verify the actual impact of the measures on the EGU dispatching and each states individual CO_2 emission rate. State air quality agencies would not be required to enforce measures as BSER which they have no control over. This approach would make the cost to reduce GHG from EE fair to all states regardless of whether they are importing or exporting. It allows CO_2 reductions at both peaking and base EGUs to be "counted". It simplifies calculating BSER goals for each state. Lastly, it simplifies tracking of EE and does not require complex negotiations between states to account for importing/exporting and avoided generation. If states wanted to implement additional EE reductions in addition to those required by a best management practices approach, the additional savings could be counted as avoided generation in a state CO_2 emissions rate. In this case, the total MWhs avoided by each state could be summed. AVERT modeling should be sufficient to estimate the quantity of CO_2 reduced for the whole country. This reduction could then be allocated to each state based on the amount of MWhs avoided. The participating state's CO_2 emission rate could then be given a credit. A second approach to allocating would be for EPA to run IPM each year to determine the amount of avoided emissions occurring at states which are going beyond the requirement. This value could be applied to the state's CO_2 emission rate. Out of state reductions that occur at non-participating states could be bought for credit by these states. In conclusion, North Carolina is one of only few states in the country with direct experience calculating avoided generation and emissions offsets. We believe EPA's approach to RE and EE is overly complicated and unnecessarily

				burdensome. If EPA proceeds with a rule that includes illegal beyond-the fence RE and EE requirements, EPA should consider this simple, transparent, enforceable and reasonable alternative path. We request EPA to strongly consider these alternatives in making the final rule.

	111d Issue Category	EPA Comment Request	Fed Reg page	NCDENR Comment Response
34	State plans, All aspects of 111d plans	The agency is soliciting comment on aspects of such CAA section 111(d) plans, as described in Section V.D of this preamble.	34900 Column 2	**NCDENR State Plan Comments** **1. State Plan Submittal Timeline** Developing a state plan under this rule involves: a. Investigating numerous implementation approaches, compliance mechanisms, and generation scenarios, b. Complicated estimation and projection methods/tools, c. Difficult enforcement and legal issues, and inter-state agreements, d. Important decision making required by parties other than the state air agency, and e. Enacting legislations and adopting rules in advance of submitting its complete plan can take years to pass. State air quality agencies are overwhelmed by the number of options and methods being presented in this proposed rule. While EPA presents some simple scenarios and approaches, NCDENR does not believe it is appropriate to limit our approach to these simple scenarios given the importance and magnitude of this rule. No state can be expected to analyze and complete these challenging tasks within one year of the proposed rule being finalized (two years if a one-year extension is granted for an individual state plan), especially given the time it takes to formulate, debate, and enact on policies and rules that would allow states to make best technical and economic decisions for the benefit of all of its citizens. EPA's aggressive timeline may prevent states from 1) performing in-depth analysis of the options allowed under the rule so that the state can make good policy decisions and 2) taking a less costly "portfolio approach" due to

its inherent complexities.

NCDENR recommends (once legal review is completed):

EPA re-write its state plan submittal requirements to allow more time to analyze the various options EPA is proposing prior to developing both an initial plan and a complete plan.

EPA should add more time to engage with appropriate state agencies to ensure the state plan concepts and other strategies for compliance would be deemed approvable before timely and costly actions are enacted or adopted as enforceable measures.

NCDENR would like EPA to add in more flexibility when various components of the plan are submitted to allow a gradual development of the more complicated building blocks and state agreements. This might include additional one or two year extension to incorporate Building Block 3 and 4 and "other measures" if they are found to be legal options and a state chooses to consider them as BSER.

EPA should develop a method for updating or even allowing a complete replacement of a state plan due to unforeseen issues such as a multi-state or third party agreements falling apart, extreme weather conditions, fuel supply shortages, and unforeseen economic crisis.

2. Requiring States to Meet EPA's "Average Cumulative Emission Performance" from 2020-2029

EPA's Interim goal is expressed as emission rates to be achieved <u>on average</u> over the 2020-2029 interim period. It calculates this emission rate as <u>cumulative</u> CO_2 emissions divided by cumulative MWh energy over

				10 years. EPA states that the 10-year period allows states flexibility for timing of program implementation as the state ramps up its programs to achieve the final performance level. This 10-year averaging approach actually requires states to follow a specific pathway (glide path) to achieve the required rate reduction through 2030. It does not allow states to choose an option that is more difficult and time-consuming to implement and would significantly reduce CO2 rates, but not <u>until later</u> in the interim period. Such an example would be building non-emitting generation sources. A state must implement some measures during the early years of the interim period or face non-compliance. NCDENR believes the interim goal concept is not flexible and is prohibitive to states that want to take early action or delayed action but still meet the goal. NCDENR recommends that EPA remove the cumulative averaging requirement and forgo the concept of an interim goal. **3. Requirement to Demonstrate Actual Performance within 10% of Plan Projection** EPA requires a state to demonstrate that the actual emissions performance is within 10% of the projected emissions performance that occurred on average over a two-year period. If the performance is not with 10%, a state must implement corrective measures. EPA provides several means of estimating the projected performance, from simple calculations to complicated energy/dispatch models. However, NCDENR believes having the actual reductions match the projected performance of the control measures within 10% accuracy will not be possible. This is especially true in the early years of the rule that will result in a massive impact to the entire electricity and energy sectors. There are too

		EPA is seeking comment on different approaches for providing such crediting or administrative adjustment of EGU CO_2 emission rates, which are elaborated further in the State Plan Considerations TSD. Credits or adjustment might represent avoided MWh of electric generation or avoided tons of CO_2 emissions. The approach chosen could have significant implications for the amount of adjustment or credit provided for RE and demand-side EE measures. If adjustment or credits represent avoided MWh, they would be added to the denominator when determining an adjusted lb CO_2/MWh emission rate. If adjustment or credits represent avoided	many unknowns that will impact EGU dispatching trends, including: 1) how other states will comply with the rule 2) existing EGU repowers and efficiency improvements, 3) new EGU generation mix, 3) future energy availability and prices, 4) legal issues when trying to implement certain parts of the rule, and 5) countless other possibilities hat have not yet been encountered or considered. If EPA chooses to keep the interim goal, NCDENR recommends that states show compliance with plan projections within a higher percentage, such as 30%, during the early years and narrowing to 10% closer to 2029. In addition, NCDENR also recommends specifying more clearly whether corrective measures will kick if <u>circumstances beyond the states control result in non-compliance</u> with the projected performance. Such circumstances may include but is not limited to: extreme weather events, low emitting EGU equipment failures, and natural gas supply issues. **4. Crediting or Administrative Adjustment of EGU CO_2 Emission Rates** EPA presents <u>many</u> options for quantifying CO_2 reductions from RE and EE. EPA states that both <u>how</u> the reductions are calculated (numerator vs denominator) and for <u>which units</u> (average or marginal) the emission factors are obtained, will greatly impact the CO_2 performance results. So, how is a state supposed to proceed? Just play with all the different methods to get the highest reductions possible? This is not a technically sound approach. It leaves states and utilities open to lawsuits based on interpretations of these methods to demonstrate compliance. It also puts states on very different playing fields in regards to "marginal units", which are defined by the generation costs of the existing EGU fleet. States like North Carolina that have already retired many inefficient coal plants and have fewer so-called marginal units would be at a disadvantage. Lastly, the options presented do not fundamentally answer the question - are actual reductions

		CO2 emissions, they would be subtracted from the numerator when determining an adjusted lb CO2/MWh emission rate.		occurring in the state CO2 emission rate? All one has to do is review the CO2 emissions data for a state's affected units and make a determination that the projected rate reduction does not match actual measurements data no matter how much modeling other analysis says otherwise. These complicated methods cannot provide a legally defensible method for a state 1) to quantify/allocate emissions and adjust its CO2 rate, and 2) may penalize early action states. Therefore, NCDENR does not recommend investing the time and effort required to develop them for incorporation into the rule. <u>A less complicated approach for this building block should be pursued</u>, (i.e., one that is not encumbered by trying to distinguish exactly which EGUs decrease generation and that is fairer to early-action and/or importer states). NCDENR has recommended several options in Building Blocks 3 and 4 comments that provide a reasonable path forward. **5. State Plan Consideration TSD - Requirements for RE and EE Programs** EPA's State Plan Considerations TSD has <u>numerous</u> proposals and requests for comments related to quantifying, verifying and allocating emissions reductions from RE and EE, including; a. Development of Guidance Documents b. Pre-Defined Requirements for Common EE Programs (lighting) c. Types of programs that have straightforward EM&V (equipment replacement) d. Grandfathering of Existing Programs (that meet approvability criteria) NCDENR does not have sufficient time and manpower to respond to these lengthy and vague proposals and requests for comments in this TSD. NCDENR provides the following general comments **A. RE Generation Quantification and Verification:** NCDENR acknowledges it is possible to quantify and verify RE generation since states already have methods and programs in place. NCDENR

				recommends building on the existing quantification and verification and RE allocation policies and programs implemented by the states to standardize these methods. **B. EE Avoided Generation Quantification and Verification:** NCDENR also acknowledges that it is possible to quantify and verify avoided generation due to some EE measures such as hardware upgrade, replacement and repair. However, many types of EE measures being implemented are more "soft" and do not provide a sufficient level of accuracy required to stand up to legal challenges. In addition, the quantification and verification methods that would be required to make an EE measure legally defensible may make certain measures too burdensome and/or costly to implement. NCDENR questions whether the actual impact on the overall CO2 rate for existing EGUs make these measures worth the effort given the burdensome and costly requirements to make legally enforceable BSER demonstrations at affected EGUs. EE is generally seen as a means to limit the growth of generation (i.e., avoid building new power plants) and not to decrease existing generation. **C. Allocation of Avoided Emissions:** The concept of allocating these avoided emissions to a particular EGU or group of EGUs is new, complicated, and with generally unknown accuracy levels. NCDENR has investigated the two basic methods for allocating emissions reductions; 1) decreasing the avoided emissions by the percentage of generation imported to total sales and 2) using the AVERT model to estimate the avoided generation/emissions at marginal units in the region. NCDENR does not see how the first approach, which is very simplistic, will not cause double counting, especially for importing states. NCDENR believes the second approach to be more robust but it penalizes importing states. The rate payers are paying for emissions reductions that happen out of state and they are unable to take credit on their state plans for the

reductions. NCDENR also questions the AVERT results for a vertically integrated system such as North Carolina, and the use of a model for long term forecasting when its dispatching algorithms are based on a single base year. EPA has indicated that the AVERT model is not intended to be used more than five years into future. See other comments regarding the AVERT results in NCDENR's Building Block 3 and 4 technical comments.

The concept of quantifying, verifying and allocating RE and/or EE avoided emissions in manner sufficient to stand up to legal challenges that may result from using these measures as BSER at EGUs in the state cannot be accomplished without extraordinary and burdensome technical and legal requirements. Therefore, if EPA chooses to finalize the rule with Building Blocks 3 and 4 included, despite the legality of this approach, NCDENR recommends that EPA develop a different approach to incorporating RE and EE into this rule that is less burdensome and less legally difficult to implement. See our comment on inclusion of RE and EE as "best management practices".

6. EPA State Plan Projection TSD - Requirements and Resources

The proposed rule requires a projection showing that a state's proposed plan measures will result in reducing CO2 emissions such that the state will meet its CO2 emission rate or mass limit in future years. These projections need to be able to estimate the actual CO2 emissions within 10% to avoid corrective measures from kicking in. This strict accuracy requirement and the complicated compliance options EPA presents preclude the use of many available resources for performing projections, as discussed below.

EPA published a TSD on the methods available to perform the projection and any readily available resources, models, and tools. EPA admits that some of the models and tools are more short-term in nature and not appropriate for 10-year forecasting (AVERT/dispatch models). Other models referenced by

				EPA do not have the ability to model the changes that will result from the various measures in the rule, such as decreased use of peaking units due to RE and EE (ERTAC). Lastly, EPA states that some states will have to model across state lines in order to accurately reflect inter-state electricity influences and markets resulting from RPS policies and multi-state trading policies. ISO/RTO dispatch and capacity models may not be able to model inter-state influences. Eliminating those models and tools that do not fit EPA's criteria for an acceptable forecasting capability leaves only complicated national-level capacity expansion and dispatch planning models such as IPM, which are generally proprietary, expensive, and require an experienced energy modeler to develop, run and analyze results. Therefore, NCDENR does not anticipate it will have the ability to utilize these models for projecting plan performance. This leads to the following issues. 1. NCDENR can only utilize less complicated models due to staffing/monetary restrictions, which will prohibit our ability to choose more complicated methods for compliance, such as a mass-based or multi-state trading approach. 2. It will limit NCDENR's ability to develop a thorough analysis of the various options and approaches available for compliance under the rule in regards to costs, reliability, reductions, and other impacts. 3. Simple models cannot project large shifts to the existing generation and dispatching that may result from this rule across all states. Use of simple models may make NCDENR's state plan vulnerable to these shifts, resulting in the plan measures not being sufficient for reducing CO2 emissions to the required level. NCDENR recommends that US EPA develop or make available, a projection tool that supports the states need to both analyze complicated options under the rule and demonstrate any proposed plan will meet the performance level

over the 10-year projection period. This tool should be at the national level to accommodate studying the impact of multi-state trading and interstate RE purchasing and be able to project changes to dispatching as a result of all 4 building blocks. Lastly, the tool has to be sufficiently robust and accurate to project emissions under various compliance scenarios to within 10% of actual emissions, even with potentially large changes to existing generation and dispatching.

As stated previously, this type of modeling will require coordination between states to obtain inputs and to run scenarios. Since all states will be developing plans within the same 1 to 3 year period, NCDENR recommends a third party, such as US EPA, be required to collect and disseminate data and support national modeling efforts.

7. Proposed Approach for Treatment of Existing State Programs and Measures in a State Plan

EPA proposes to not give states credit for

1. EE measures installed prior to the rule proposal date (2014) and

2. EE savings achieved prior to the performance period (2014-2020)

This will severely penalize early action states such as North Carolina. North Carolina expects to have significant avoided generation occurring between 2012 and 2020 due to our NC REPS Rule. Based on the Duke Energy Carolinas IRP and Duke Energy Progress IRP, expected cumulative EE savings are 16,849 GWh due to EE programs implemented throughout the state as shown below. NCDENR estimates that existing EE programs in the state will avoid over 9 million tons of CO_2 between 2014 and 2019.

Load Forecast with and without Energy Efficiency Programs from 2013 IRPs

	Duke Energy Carolinas	Duke Energy Progress

Year	With EE GWh	Without EE GWh	EE Savings GWh	With EE GWh	Without EE GWh	EE Savings GWh
2014	65,333	65,656	**323**	92,943	93,566	**623**
2015	66,338	66,895	**557**	94,721	95,762	**1,041**
2016	67,335	68,141	**806**	96,475	98,023	**1,548**
2017	68,182	69,211	**1,029**	98,226	100,356	**2,130**
2018	69,126	70,361	**1,235**	100,032	102,773	**2,741**
2019	70,146	71,613	**1,467**	101,678	105,027	**3,349**
Cumulative Duke Energy Carolinas and Progress (2014-2019) in GWh						**16,849**
Cumulative CO2 Avoided Emissions in tons						**9,044,964**

Calculated using EPA EGRID 2010 SVRC emission factor for CO_2

The EPA stated in its press releases that it gives credit to forward thinking states for their CO_2 reductions. However, in practice, it does not credit these states. In fact, this approach will actually punish states for four reasons;

1) It does not allow states to repeal/discontinue existing programs/rules that reduce CO_2 until 111d plans are approved. So states will have to go forward with these programs while getting no credit.

2) EE measures that have an expected life greater than 5 years tend to be more expensive hardware replacement programs. These programs have greater impact than softer behavior modification measures. Yet, EPA does not allow any credit for these programs if they were installed prior to June 2014, even though these hardware replacements will result in verified savings after 2020.

3) The 9 million tons of CO_2 projected to be avoided between 2014 and 2019 will be achieved at a considerable cost to rate payers in North Carolina.

		In light of current state programs, and of stakeholder expressions of concerns over the above-noted issues, including legal		4) The EE measures that will remain in 2020 as options to implement by the early action states are more costly than the options available to states who have not acted on EE. These costs will be passed on to the rate payers who have already done their part in meeting EPA's overall 30% reduction goal. NCDENR notes that under a mass-based approach, EPA appears to allow a state to give credit to these programs on some level by <u>not</u> including EE programs implemented after 2015 in projections. EPA seems to be forcing early action states to implement a mass-based approach. NCDENR recommends that EPA change the proposed rule to allow states that have achieved significant avoided CO2 emissions during 2014 to 2019 due to existing EE programs, to receive credit under <u>both</u> a rate-based and mass-based for their achievements. At a minimum, more permanent hardware replacement programs should be given credit for savings realized during the performance period, regardless of when they were installed. NCDENR recommends utilizing a system similar to our REPS rule regarding credits for EE avoided generation. The NC REPS Rule allows <u>banking</u> of avoided generation from energy efficiency. Each MWh of avoided generation is verified and registered into the NC RETS banking system along with the vintage of the credit. The credit can be used during the present year or future years to comply with the REPS rule. Since EE savings are easier/cheaper to achieve at the beginning of a long term state-wide EE program, this allows electricity distributors flexibility in complying with the rule in a cost-efficient manner. In developing this pre-rule banking system EPA should develop limits on 1) the type of EE measures that are given credit, 2) the measure life, and 3) the vintage of the credit to ensure only real savings are credited during 2014 to 2020. **8. State Plan - Enforcement of Building Blocks 3 and 4 – Responsible Party** U.S. EPA presents three basic scenarios above for enforcing RE and EE

		enforcement considerations, with respect to those programs, the EPA is proposing to authorize states either to submit plans that: • Hold the affected EGUs fully and solely responsible for achieving the all of the emission performance level. Note a mass-based approach would not require RE and EE to be federally enforceable since this approach puts all responsibility for emissions reductions on the affected EGUs. • Rely on measures imposed on third party entities to achieve a portion of the emission performance level, • Place the responsibility for building block 3 and/or 4 on the state such that the state could face penalties if the measures are not implemented. • The EPA requests comment on the proposed approaches. In addition, the EPA is soliciting comment on several other types of state plans that may assure the requisite level of emission performance without rendering	requirements. It also presents a "state commitment approach" to decrease the enforcement requirements from federally enforceable to state enforceable with the state becoming the responsible party. Lastly, the EPA suggests that a mass-based approach would not require RE and EE to be federally enforceable since this mass approach puts all responsibility for emissions reductions on the affected EGUs. NCDENR does believe there is sufficient evidence that these building blocks can be legally enforceable emissions performance standard at affected EGUs, no matter who the responsible party is. An affected EGU or group of EGUs cannot enforce RE and EE programs, especially in non-vertically integrated states. A state's air quality agency has no legal authority to impose or enforce an RE or EE program as a means of reducing emissions at EGUs. In addition, a state utilities commission generally has no prescriptive enforcement mechanism in place regarding RE or EE programs. RE and EE programs are generally <u>incentive driven</u> rather than enforcement driven. Therefore, NCDENR does not recommend implementing Building Block 3 and/or Building Block 4 as part of an <u>emissions performance standard</u> for affected EGUs. As stated previously, if EPA chooses to finalize the rule with Building Blocks 3 and 4 included despite the legality of this approach, NCDENR recommends that EPA develop a different approach for incorporating RE and EE programs into this rule that is less burdensome and less legally difficult to implement. See our comments on implementing these building blocks as "best management practices" in all states.

		certain types of measures federally enforceable and that limit the obligations of the affected EGUs.	**9. Portfolio Approach and 'State Commitment Approach** NCDENR does not recommend implementing building blocks 3 and 4 as part of an emissions performance standard for affected EGUs, no matter how it is implemented (EGU limit, portfolio approach credit, or state commitment credit). Avoided generation cannot be allocated to a particular EGU or group of EGUs. Therefore, it cannot be used as BSER for an EGU. NCDENR recommends the "state commitment approach" be included as part of a new approach to implement Building Block 4 as "best management practices".
		The EPA is requesting comment on the appropriate frequency of reporting of the different proposed reporting elements, considering both the goals of minimizing burdens on states and ensuring program effectiveness. In particular, the agency requests comment on whether full reports should only be required every two years.	**10. Plan Performance Reporting Schedule** NCDENR does not foresee any problems in an average two year reporting cycle for emissions performance related to EGU (fossil and non-emitting/renewable) generation and emissions. However, NCDENR does anticipate significant issues with reporting verified EE avoided generation in MWhs. North Carolina currently has a system in place for both third party EM&V and reporting of EE avoided generation. It currently requires electricity distribution companies to report the estimated EE MWhs saved annually from each EE program. However, EM&V of each MWhs may not occur in that same time frame. The current reporting system allows for companies to perform EM&V in several different ways, depending on the program. EM&V reports for certain types of programs may take several years to finalize. The current reporting system allows for corrections to be made from errors reported in the past. However, those corrections are <u>not</u> applied retroactively. Instead, the avoided MWhs for the current year are

				adjusted to reflect the increase or decrease in generation. As stated previously, NCDENR recommends that EPA develop a different approach for incorporating RE and EE programs into this rule that is less burdensome and less legally difficult to implement. See our comments on implementing these building blocks as BSER.
		The EPA is proposing that state plans must include a record retention requirement of ten years, and we request comment on this proposed timeframe.		**11. Records Retention** A record retention time of 10 years will not be sufficient since the interim goal period is 10 years and the life of some EE reduction measures is greater than 10 years. NCDENR recommends a slightly longer retention time of 12 to 15 years to ensure sufficient data is available to calculate and adjust the goals. In addition, NCDENR recommends that data associated with EE measures that extend beyond 10 years maintain a record retention time for the entire life of the EE measure, with a maximum of 20 years.