ENVIRONMENTAL MANAGEMENT COMMISSION
FISCAL AND REGULATORY ANALYSIS FOR PROPOSED ADOPTION STANDARDS OF PERFORMANCE FOR EXISTING ELECTRIC GENERATING UNITS UNDER CLEAN AIR ACT SECTION 111(D).

Rule Adoption:	15A NCAC 02D Section .2700 (see proposed rule text in Appendix 1)
Rule Topic:	Standards of Performance for Existing Electric Generating Units under Clean Air Act Section 111(d).
NCDEQ Division:	Department of Environmental Quality, Division of Air Quality
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Impact Summary:	State government: No Local government: No Substantial impact: Yes
Statutory Authority:	G.S. 143-215.3(a)(1); 143-215.107(a)(1), (3), (4), (5); 143-215.108; 143B-282;.
Necessity:	To Implement requirements for Existing Sources under Section 111(d).

I. Executive Summary

On October 23, 2015 the Environmental Protection Agency (EPA) finalized emission guidelines for states to follow in developing plans to reduce greenhouse gas (GHG) emissions from existing fossil fuel-fired electric generating units (EGUs). Specifically, EPA is establishing Carbon dioxide (CO_2) emission performance rates representing the best system of emission reduction (BSER) for two subcategories of existing fossil fuel-fired EGUs—fossil fuel-fired electric utility steam generating units and stationary combustion turbines. EPA included state-specific CO_2 goals, reflecting the CO_2 emission performance rates, and guidelines for the development, submittal and implementation of state plans that establish emission standards or other measures to implement the CO_2 emission performance rates, which may be accomplished by meeting the state goals. The State of North Carolina, Department of Environmental Quality (NCDEQ), Division of Air Quality (DAQ) is proposing rules to reduce CO_2 emissions from affected EGUs while maintaining consistent with Clean Air Act Section 111(d) and 40 CFR Part 60, Subpart B requirements.

15A NCAC 02D Section .2700, Standards of Performance for Existing Electric Generating Units under Clean Air Act Section 111(d), are proposed rules for adoption to comply with federal requirements that facilities limit their emissions of CO_2. Table 1, Impact Summary of the State Plan by North Carolina, presents the estimated economic impacts to affected parties due to these rule adoption. The private sector impacts reflect the changes facilities may see as a result of the proposed rule from the baseline scenario. The proposed rules are expected to affect 10 coal-fired units at 5 facilities, out of 24 existing coal-fired units at 9 facilities and 32 existing natural gas combined cycle units at 8 facilities. Private sector sources are required to make changes due to these proposed rules, which are beyond the measures that have already occurred because of previous and ongoing efforts to reduce GHG emissions.

No direct state government impacts occur to the State of North Carolina are estimated as the difference in annual costs between the projected baseline and the proposed rules. Similarly, DAQ expects no fiscal impacts for the three units of local government (Mecklenburg County Air Quality, Western NC Regional Air Quality Agency, and Forsyth County Office of Environmental Assistance and Protection) that operate air quality programs in North Carolina.

Table 1, Impact Summary of the State Plan by North Carolina, shows details of the $5.89 million benefit (net present value, NPV) of the state plan. Beginning in 2019, the annual impacts grow from a net positive of $923,000 to a net positive of $471,000 by 2030. The estimated annual costs and benefits of these proposed rules meet the threshold of substantial economic impact, as defined in North Carolina's Administrative Procedures Act, NC General Statute 150B-21.4 (i.e., an aggregate financial impact on all persons affected of at least one million dollars in a 12-month period).

Table 1. Fiscal Impact Summary of the State Plan by North Carolina

Year	Local Government	State Government	Private Sector (Costs)	Private Sector (Savings)	Total Impact (+ Cost, - Savings)
2016	$0	$0	$0	$0	$0
2017	$0	$0	$0	$0	$0
2018	$0	$0	$0	$0	$0
2019	$0	$0	$6,394,000	-$7,317,000	-$923,000
2020	$0	$0	$6,510,000	-$7,397,000	-$887,000
2021	$0	$0	$6,626,000	-$7,479,000	-$853,000
2022	$0	$0	$6,746,000	-$7,561,000	-$815,000
2023	$0	$0	$6,868,000	-$7,644,000	-$776,000
2024	$0	$0	$6,992,000	-$7,728,000	-$736,000
2025	$0	$0	$7,117,000	-$7,813,000	-$696,000
2026	$0	$0	$7,245,000	-$7,899,000	-$654,000
2027	$0	$0	$7,375,000	-$7,986,000	-$611,000
2028	$0	$0	$7,509,000	-$8,074,000	-$565,000
2029	$0	$0	$7,643,000	-$8,163,000	-$520,000
2030	$0	$0	$7,781,000	-$8,252,000	-$471,000
NPV*	$0	$0	$55,337,000	-$61,225,000	-$5,888,000
* NPV – Net Present Value – is as of July 1, 2015, and uses the statutorily mandated 7% discount rate.					

II. Background

1. Introduction

The United States Environmental Protection Agency (EPA) finalized Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units[1] on October 23, 2015, and codified them in 40 CFR Subpart UUUU.

The affected electric utility steam generating units (EGUs) under these emission guidelines are steam generating units, integrated gasification combined cycle units (IGCC), and stationary combined cycle or combined heat and power (CHP) combustion turbines that commenced construction on or before January 8, 2014.

The emission guidelines include uniform, nationwide emission standards, which are performance-based rates for emissions of greenhouse gases (GHG) expressed as CO_2 (lbs. CO_2/net MWh), as follows:

Table 2. Uniform Emission Performance Rates (lbs. CO_2/ net MWh)

	Interim, average of 2022-29	Final, starting 2030
Fossil fuel-fired steam generating units or IGCC	1,534	1,305
Natural gas-fired stationary combined cycle combustion turbines (including CHP combustion turbines)	832	771

In lieu of the above uniform rates, each EGU can comply with state-specific goal (lbs. CO_2/net MWh). The other option is that all affected units in the state, in aggregate, comply with the mass-based state goal (short tons/yrs.).

Table 3. North Carolina Specific Goals

	Interim, average of 2022-29	Final, starting 2030
NC Aggregate Rate Goal (lbs. CO_2/ net MWh)	1,311	1,136
NC Aggregate Mass Goal (tons/year)	56,986,025	51,266,234

The above standards (whether uniform nationwide rates or state-specific goals) are based upon the determination of Best System of Emissions Reduction (BSER) consisting of following three building blocks:

[1] US EPA. Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units. August 3, 2015. http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf

- Building Block 1 (BB1) - reducing the carbon intensity of electricity generation by improving the heat rate of existing coal-fired power plants;

- Building Block 2 (BB2) - substituting increased electricity generation from lower-emitting existing natural gas plants for reduced generation from higher-emitting coal-fired power plants; and

- Building Block 3 (BB3) - substituting increased electricity generation from new zero-emitting renewable energy sources (like wind and solar) for reduced generation from existing coal-fired and natural gas-fired power plants.

The emission guidelines require that each state submit its plan complying with all applicable requirements by September 6, 2016. One of the requirements consists of development of an emission standard ("standard of performance") and establishment of compliance time for each EGU.

The Clean Air Act (CAA) Section 111(a)(1) defines "standard of performance" as: "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated".

2. History of Development of Emission Guidelines under CAA

Over the last 40 years, under Section 111(d), the EPA has regulated four pollutants from five source categories, by promulgating associated emission guidelines. These source categories are phosphate fertilizer plants (fluorides), sulfuric acid plants (acid mist), Kraft pulp plants (total reduced sulfur (TRS)), primary aluminum plants (fluorides), and municipal solid waste landfills (landfill gas emissions as non-methane organic compounds (NMOCs)).[2] The following general principles and/or rationales were used by EPA in establishing BSER for these emission guidelines:

- The degree of emission reduction achievable through the application of various demonstrated control technologies;

- The technical feasibility of applying various demonstrated technologies to existing sources considering variability in sizes and designs;

[2] See Footnote 18 at 79 FR 41776, July 17, 2014, including ''Phosphate Fertilizer Plants; Final Guideline Document Availability,'' 42 FR 12022 (March 1, 1977); ''Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist,'' 42 FR 55796 (October 18, 1977); ''Kraft Pulp Mills, Notice of Availability of Final Guideline Document,'' 44 FR 29828 (May 22, 1979); ''Primary Aluminum Plants; Availability of Final Guideline Document,'' 45 FR 26294 (April 17, 1980); ''Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule,'' 61 FR 9905 (March 12, 1996).

- The impact of various demonstrated technologies on national energy consumption, water pollution, waste disposal, and ambient air concentrations of a designated pollutant; and

- The cost of adopting the emission guidelines, after considering control costs for various demonstrated technologies and taking into account the level of any existing controls.

Each of these emission guidelines indicate that the cost of applying various control technologies can have a considerable impact in selection of a BSER for any designated pollutant for existing facilities. They also indicate that the age, size, type, class, and process design of the facility, influence not only the BSER selection process, but can also support a decision-making for whether different emission guidelines are to be established for differing sizes, types, or classes of equipment.

The emission guidelines for the above referenced source categories have been established for principal points of emissions (point and fugitive emissions sources) located within the facility and, not for any emissions sources located outside of the facility. Finally, in these emission guidelines, with respect to determining the emission guideline, EPA has consistently recognized that not only the control technology needs to be demonstrated on existing sources, but the degree of emission reduction (performance level) needs to be readily achievable by the control technology.

3. The Division of Air Quality (DAQ)'s Approach for Determination of BSER

The DAQ considered the above general principles in determining BSER for CO_2 emissions reduction from each EGU. But, importantly, DAQ determined BSER for each EGU based upon BB1-type measures only (i.e., measures which can be accomplished within the fence-line of the facility), conforming to the Section 111(d) of the CAA and the requirements of 40 CFR 60 "Adoption and Submittal of State Plans for Designated Facilities". Thus, DAQ's approach comprises of improving the operational efficiency of the EGUs in order to reduce CO_2 emissions from the 2012 baseline levels.

The DAQ specifically based its BSER evaluation upon the following:

- type of EGU,
- remaining useful life of the EGU,
- unit's baseline data (net heat rate, net generation, annual capacity factor, and CO_2 emissions),
- unit's projected future capacity factor,
- feasibility of applying specific heat rate improvement (HRI) measure on a given unit,
- whether the measure is "adequately demonstrated",[3]
- degree of heat rate reduction potential for feasible HRI measures,
- site-specific limitations,

[3] See page 296 of 1560 (pre-publication version), Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units Clean Power Plan, August 3, 2015.

- associated costs (capital, fixed and variable operational and maintenance (O&M), and fuel and reagent savings), and
- cost per ton of CO_2 reduction.

The evaluation is also based on literature review[4] of technical feasibility for various HRI measures, degree of heat rate reduction potential, and costs data (capital, and fixed and variable O&M).

It needs to be emphasized here that DAQ's determination for each EGU is not based upon some pre-determined HRI target, such as EPA's selection of a 4.3 percent HRI potential for EGUs in the Eastern interconnection,[5] as discussed in the emission guidelines.

The DAQ's approach includes those adequately demonstrated, cost-effective measures that assure that the electricity is generated with lower CO_2 emissions, thus improving public health and welfare. The selected HRI measures would be expected to produce non-air environmental co-benefits in the form of reduced water usage and solid waste production, in addition to, reductions in emissions of non-GHG pollutants such as SO_2, NOx, and mercury. However, it should be noted that as the EGU becomes more cost-competitive due to HRIs, it may be utilized more frequently and/or at higher loads. If the EGU is utilized more often, some increases in emissions of GHG (as CO_2) and non-GHG pollutants (such as SO_2, NOx, or mercury) are possible, and those could partially offset the emissions reductions achieved through the HRI of the EGU.

EPA has determined a cost estimate of $23 per ton[6] reasonable for CO_2 emissions reduction from EGUs under BB1 implementing HRI measures. EPA has further determined that this cost is reasonable because it achieves "an appropriate balance between cost and amount of reductions."[7] According to the EPA, a cost of $23 per ton of CO2 associated with building block one falls within the range of EPA's social cost of carbon estimates at a 5% discount rate. [8] The EPA uses the social cost of carbon as a broad range of estimated monetary value of impacts associated with marginal changes in CO2 emissions in a given year. The DAQ used the cost effectiveness

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[4] "Coal-fired Power Plant Heat Rate Reductions", Final Report, Sargent & Lundy, Chicago, IL, January 22, 2009.
"Analysis of Heat Rate Improvement Potential at Coal-Fired Power Plants", US Energy Information Administration, Washington, DC, May 2015.
S. Corellis, "Range and Applicability of Heat Rate Improvements", Technical Update, Electric Power Research Institute, Palo Alto, CA, April 2014.

[5] Applies to coal-fired EGUs only.

[6] See page 446 of 1560 (pre-publication version), Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units Clean Power Plan, August 3, 2015.
Based on nation-wide coal fleet capacity of 213 GW, heat rate improvement capital cost of $100/KW, capital charge rate of 14.3%, fleet-wide baseline net heat rate of 10,250 Btu/KWh, heat rate improvement of 4% for coal-fired EGUs, annual capacity factor of 78%, and future (2030) average coal delivered cost of $2.70 per million Btu. See page 2-65, Greenhouse Gas Mitigation Measures, Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants", August 3, 2015.

[7] See page 457 of 1560 (pre-publication version), Ibid.

[8] US EPA. Climate Change. The Social Cost of Carbon.
http://www3.epa.gov/climatechange/EPAactivities/economics/scc.html.

threshold of $23 per ton to determine reasonableness of cost for each of the technically feasible measure in determining BSER for a particular EGU.

4. BSER Evaluation

The information DAQ used in determining BSER included:

- Baseline data (net heat rate, net generation, generation-based annual capacity factor, and CO_2 emissions) for 2012,
- Projected heat input for 2019,
- Cost data (capital cost and annual O&M),[9] and
- Project life, degradation factor, and HRI potential for each measure considered for implementation at a EGU.

In the final Clean Power Plan rule (40 CFR 60 Subpart UUUU) for existing EGUs, EPA "considered heat rate improvement opportunities at oil- and gas-fired steam EGUs and NGCC units and found that the available emission reductions would likely be more expensive or too small to merit consideration as a material component of the BSER." Based on the EPA determinations and considering the nature of operations, DAQ believes that efficient NGCC technology combined with the use of clean fuels (natural gas and distillate fuel) is BSER. Therefore, the proposed rule does not require NGCC units to implement additional BSER measures.

DAQ then considered the following measures for possible implementation on all EGUs of NC-based coal-fired fleet:

- Controllable Loss Reduction (Maintain Unit Efficiency) [CLR],
- Sliding Pressure Operation [SPO],
- Lower FGD Efficiency (as SO_2 permit limits allow) [FGD],
- Intelligent Sootblowers [ISB],
- Air Heater Leakage Reduction [ALR],
- Combustion Optimization - CCM / Excess Air / Neural Network [CO],
- Online Condenser Cleaning [OCC],
- Induced and/or Booster Draft Fan Variable Frequency Drive [IBD],
- Air Heater Exit Gas Temperature Reduction [AHE],
- Flue Gas Desulfurization (FGD) Auxiliary Load Reduction through Variable Frequency Drives [FGD],
- Boiler Feed Pump Motor Driven Variable Frequency Drive [BFP],
- Induced Draft Fan Replacement [IDFR],
- Forced Draft Fan Variable Frequency Drive [FDF],
- Condenser Rebundle, Retubes, and Rebuilds [CRR],
- Electrostatic Precipitator (ESP) (Power management, T/R set upgrades) [ESP],
- Turbine Upgrades (HI, IP, LP) [TUR], and
- Helper Cooling Tower [HCT].

[9] High level estimate in the range of -20% to +75% in 2015 dollars.

In evaluating the different measures, DAQ also considered a number of factors that impact the feasibility and efficacy of heat rate improvement measures:

- In general, HRIs decrease over time because the equipment associated with each measure degrades over time due to normal wear and tear;

- Some of the efficiency projects cannot be performed, or the full HRI benefits may not be realized, due to unique configuration or physical limitation of a given EGU;

- Operation of any EGU at less than the full load, or if cycled between full and partial load, can adversely impact an EGU's heat rate. Reduced utilization of the coal-fired fleet in North Carolina has been seen in recent history in response to lower natural gas prices, resulting in some coal-fired units, once operated as base-load units (i.e. high capacity units), now operating as intermediate duty cycling units; and

- Any post combustion environmental controls (activated carbon for mercury control, dry bottom and fly ash conversion for coal ash disposal, selective catalytic reduction for NOx control, and Zero Liquid Discharge (ZLD) for wastewater treatment) also adversely impact the heat rate of the EGU.

With respect to evaluation, the DAQ has utilized or considered the following data, upon verifying or through calculations, for estimating heat rate reduction (Btu/kWh), CO_2 emission reduction (short tons/year), and cost per unit reduction of CO_2 ($ per ton) for each measure:

- Baseline (2012) CO_2 Emissions,
- Baseline (2012) Net Heat Rate,
- Baseline (2012) Net Generation,
- Baseline (2012) Heat Inputs,
- Baseline (2012) Annual Capacity Factor - (heat input basis),
- Future (2019) Projected Annual Capacity Factor – (heat input basis),
- Future (2019) Projected Coal Delivered Cost, and
- Remaining Useful Life of the Unit.

DAQ used the average actual coal delivered prices for 2014 from Duke Energy Carolinas of $3.84 per million of Btu[10] and Duke Energy Progress of $3.57 per million Btu,[11] and estimated the coal delivery price for 2019 based on forecasted delivery prices from the US Energy Information Administration (EIA) to be $3.92 per million Btu (see Appendix 2 for the calculations).[12]

[10] Duke Energy Carolinas, actual, average cost of fuel burned for 12 months ending December 2014 (See NCUC Docket No. E-7, Sub 1047, Duke Energy Carolinas, LLC Monthly Fuel Report, February 11, 2015).
[11] Duke Energy Progress, actual, average cost of coal burned for 12 months ending January 2015 (See NCUC Docket No. E-2, Sub 1064, Duke Energy Progress, INC. Monthly Fuel Report, March 12, 2015).
[12] Forecast delivery prices were based on the US Energy Information Administration's Annual Energy Outlook 2015, available at: http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf .

As mentioned above, DAQ eliminated some candidate measures from consideration for particular facilities due to technical infeasibility. The agency also removed from consideration measures that would result in collateral increases of emissions of other pollutants. DAQ did not consider as a candidate BSER measure for a facility any measures implemented at that facility prior to the 2015 start of DAQ evaluation of BSER.

On a unit-by-unit basis, DAQ evaluated the remaining measures (all except, technically infeasible measures, measures implemented prior to 2012, measures implemented between 2012 and July 31, 2015, and measures which increase collateral emissions) using the methodology described below.

First, using the project life (yr) for a given measure, DAQ transformed capital investment ($) into an indirect annual (capital) cost ($ per yr) by simply dividing capital investment by the project life. Then, it added it to the direct annual (fixed O&M) cost to determine the total annual cost.

Next, using the coal delivered price, baseline year (2012) generation and capacity factor, future capacity factor, and average HRI percent (calculated assuming the HRI for a given measure degrades linearly over the project life based on degradation factor); coal fuel savings were estimated for 2019. DAQ deducted fuel savings due to heat rate improvements from the total annual cost to determine net annual cost for implementation of a measure.

Then, using baseline CO_2 emissions, baseline and future capacity factors, and average improvement of heat rate for EGU (again, assuming a decrease in HRI linearly over the measure's life based on degradation factor) from baseline net heat rate, DAQ estimated the reduction in CO_2 emissions associated with a given measure.

Finally, the agency estimated the cost per unit reduction in CO_2 by taking net annual cost and dividing it by CO_2 emissions, both determined as above.

Average HRI percent (calculated using degradation factor across the project life) and not the maximum HRI percent, was applied to determine fuel savings and CO_2 emissions reductions for a given measure.

Some of the units are projected to operate at a very low annual capacity factors. Thus, for those units many of the measures included for HRIs are expected to present significant costs, exceeding the reasonable cost threshold. If any of those EGUs were to operate at a higher annual capacity factor, then the cost per unit reduction of CO_2 would be reduced.

In summary, DAQ concluded that the estimated costs in $ per ton for some of the measures is unreasonable using the cost threshold of $23 per ton CO_2. Thus, DAQ determined that none of those measures are BSER. The other measures with an estimated cost for a particular EGU under the threshold were included as a required BSER for that particular EGU in the proposed rule adoptions.

III. Proposed Rules

NCDEQ is proposing to adopt rules in 15A NCAC 02D Section .2700, Standards of Performance for Existing Electric Generating Units under Clean Air Act Section 111(d), to satisfy similar federal requirement of the regulation of GHG emissions. Section 111(d) requires EPA to identify the "best system of emission reduction" (BSER) that is adequately demonstrated and available to limit pollution and to set guidelines for states to reflect BSER. Based on its evaluation of BSER for existing EGUs, the EPA proposed regulation provides state specific goals for reducing carbon dioxide (CO_2) emissions for the power sector. States are then required to develop a plan including necessary rules to meet those goals.

The proposed rules are in Section .2700 – Standards of Performance for Existing Electric Generating Units under Clean Air Act Section 111(d) – as follows:

- 15A NCAC 02D .2701, Purpose and Applicability, is proposed for adoption to implement the Clean Air Act (CAA) Section 111(d) guidelines for existing EGUs under 40 CFR 60 Subpart UUUU Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units (EGU). This rule specifies which fossil fuel-fired steam EGUs are subject to regulation under the Clean Air Act Section 111(d);

- 15A NCAC 02D .2702, Definitions, is proposed for adoption to define terms that are used;

- 15A NCAC 02D .2703, Standards of Performance Requirements for Carbon Dioxide, is proposed for adoption to identify the BSER measures for carbon dioxide emissions at affected EGUs located in North Carolina. This rule also contains a compliance schedule for implementing the identified BSER measures;

- 15A NCAC 02D .2704, Permitting, is proposed for adoption to define the permit requirements for affected EGUs; and

- 15A NCAC 02D .2705, Monitoring, Recordkeeping and Reporting, is proposed for adoption to specify the monitoring, recordkeeping and reporting requirements for each BSER measure implemented under 15A NCAC 02D .2703.

The following measures describe the Best System of Emission Reduction:

- Air heater leakage reduction (ALR). By preheating combustion air with heat transfer from exiting flue gas, less coal is required to produce the same amount of steam. Air in-leakage occurs and, as a result, reduce the pre-combustion air temperature and increases the exiting flue gas, requiring greater coal consumption. An AHR measure consists of replacing the original seals with newer high performance seals;

- Combustion optimization with neural network system (CO). The complexity of monitoring, control and optimization of a coal-fired power plant over its normal operating conditions is best achieved by a digital control system. Advancements have produced computer models, known as neural networks that simulate the power plant at various conditions, with the predicted performance results correlated to several real time process measurements. A CO system is designed to receive combustion-related and boiler performance data inputs, which are then processed to evaluate real-time performance to maximize boiler efficiency and minimize air pollutant emissions;

- Controllable loss reduction (CLR). There are many activities related to operations and maintenance known as best practices, which offer significant opportunity for heat rate improvement. Such activities involve a comprehensive effort collecting information unable to be readily collected through computerization. CLR consists of collecting and reporting information on the ongoing performance of all equipment in a power plant;

- Forced draft fan variable frequency drive (FDF). Replacing a fixed speed electric motor and a flow control damper for a forced draft fan with a variable frequency drive reduces the auxiliary power requirement by reducing the drive's speed when maximum gas flowrate is not required during part load conditions. A forced draft fan FVF controls gas flowrate electrically and consists of a static controllable rectifier to control electrical frequency and voltage and, thereby, the fan speed and gas flowrate; and

- Intelligent sootblowing (ISB). Sootblowers remove built-up ash by injecting high pressure steam or air onto heat transfer surfaces to restore performance. Intelligent sootblowers (ISB) monitor furnace exhaust gas temperatures and steam temperatures and activate when boiler operation indicates the need to remove ash rather than activating sootblowing at presumed time intervals.

IV. Changes from the Regulatory Baseline

Beyond the accomplishments of the Clean Smokestacks Act, there are no current requirements in North Carolina that form the basis of the regulatory baseline. Significant accomplishments have occurred due to those ongoing efforts related to the Clean Smokestacks Act, which are documented in annual reports filed with NCDEQ.[13] As proposed, 15A NCAC 02D Section .2700 establishes work practice standards for EGU in North Carolina using a case-by-case approach that considers the cost effectiveness of any required measure as well as the remaining useful life of the EGU.

One possible prediction of the future without the proposed rules, referred to as the regulatory baseline, includes requirements under the EPA's regulation known as the Clean Power Plan (CPP). That plan relies on three building blocks that include measures that reach beyond the fence line of the electrical generating units that are regulated under the Clean Air Act. A portion of that proposal, known as Building Block 1, calls for heat rate improvements at existing power plants. However, the EPA's proposed approach is facing legal challenges and it is possible that it may not survive in the courts. Therefore, for the purposes of this fiscal and regulatory analysis, DAQ measured changes from the baseline against a future condition without any federal plan. Taking this approach accounts directly for the impacts of the proposed state plan.

[13] NCDEQ. Division of Air Quality. Clean Air Legislation. http://daq.state.nc.us/news/leg/

V. Estimating the Fiscal and Regulatory Analysis Impacts to Affected Sources

Any facility that is required to reduce GHG emissions may incur capital costs expressed as an annualized expenditure, as well as annual operation and maintenance costs and monitoring, reporting, and recordkeeping costs. Most of these expenses will be to obtain heat rate improvements (HRI) because these are cost effective methods to comply with these regulations.

State and Local Government Impacts

Neither the State's Division of Air Quality nor any of the three local air quality programs would experience any changes in costs or revenues due to these GHG reductions at facilities because Title V fees (large permitted sources) are not assessed for CO_2 emissions.

DAQ's review of the evaluations of heat rate improvements would occur as part of the regular permitting process, and given that the Division has already run the analysis on the BSERs as part of this rulemaking, the agency estimates that any impact on DAQ permitting staff time would be minimal. DAQ also does not expect that the time to inspect the affected EGUs would be affected in any significant way. Therefore, the DAQ does not expect additional impacts from the proposed rules.

The proposed rules do not affect any EGU that falls under the jurisdiction of any of the three local air quality program; thus, the agency expects there to be no impact on any local government unit as a result of the proposed rules.

Private Sector Impacts

Table 4 presents the cost estimate for collecting and reporting the records required to satisfy the annual reporting requirements in 15A NCAC 02D .2705. The estimates are based on DAQ plans to design requirements for piggybacking any state monitoring, recordkeeping and reporting requirements onto those already established and practiced by the facilities to meet the requirements of the federal energy (U.S. Department of Energy) and environmental agency (EPA). The estimates are also based on the facts that all the data monitoring is achieved:

- by state-of-the-art computer technology with automated data processing at all the facilities,
- with an economy-of-scale in that the regulatory requirements are essentially similar at the coal-fired and natural gas-fired EGUs for reporting heat inputs, electrical generation, heat rates, and carbon dioxide emissions,
- under existing federal requirements to monitor, collect and report the data for heat input, electrical generation, and carbon dioxide emissions, and
- under the existing practice to report heat rate data, given that heat rate is the metric most often used in the electric power generation industry to track and report the performance of fossil fuel-fired power plants.

There are nine coal-fired EGU facilities and eight natural gas-fired EGU facilities in North Carolina covered under the 111(d) rule. The agency is using conservative estimates as the basis for the overall effort to collect and report the same data that the facilities have already been reporting to federal agencies for years. DAQ expects that staff at each facility would spend no more than an additional 50 hours a year at a labor cost of $100/hour to report the same data to DAQ as they have been reporting to federal agencies. The basis for these assumptions is information the agency collected on hourly cost estimates for similar engineering services provided by private contractors, which the Division has used in previous fiscal and regulatory impact analyses from 2015. Table 4 shows that the total cost estimate for such reporting is approximately $85,000 annually.

Table 4. Private Sector Cost Estimate for Monitoring, Recordkeeping and Reporting Requirements under 15A NCAC 02D .2705

Estimates for Form A4 Submittals	Facilities	Labor hours per facility	Labor cost, $/hr	Cost, $
Coal fired EGU facilities	9	50	100	45,000
NGCC EGU facilities	8	50	100	40,000
Total for all EGU facilities				85,000

Table 5, Total Annual Cost of the Proposed Rules, presents the calculated expected impacts on the affected EGUs due to the proposed rules. Using the methodology described in section II.4., DAQ estimated the annualized total capital expenditure at $51.82 million for all affected EGUs in 2019 and the annual fixed and variable operation and maintenance costs at $3.01 million in 2019. The regulated community provided information in 2015 dollars regarding the likely capital and operation and maintenance costs they would incur from implementing a certain BSER measure. The DAQ supporting documentation for this rulemaking, available on the agency's website, contains information, data, and calculations of the costs EGUs would incur for different BSER measures.[14] For the purposes of this analysis, DAQ assumes that these costs incorporate any staff time costs (opportunity costs) and interest costs related to loans necessary to invest in a required measure. To the extent that the regulated community may have additional costs than those reported, the estimated annual costs below may be higher. Table 5 also included the monitoring, recordkeeping and reporting costs, on an annual basis, as discussed above.
The analysis assumes that the annualized capital expenditures, annual operation and maintenance costs, and the compliance costs related to monitoring, reporting, and recordkeeping would grow at a rate of 1.8 percent annually from 2019 through 2030 (based on the forecast for the GDP chain-type price index EIA used in the Annual Energy Outlook 2015).[15]

[14] Supporting Basis for Determination of Best System of Emissions Reduction for Carbon Dioxide (CO2) Emissions from Existing Electric Utility Generating Units
http://daq.state.nc.us/Calendar/Planning/November2015AQC/Agenda_3.2.pdf
[15] US Energy Information Administration. Annual Energy Outlook 2015. Table A20.
http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf

Table 5. Total Annual Cost of the Proposed Rules

Year	Total Capital Recovery Costs, Annual Basis	Fixed & Variable Operation & Maintenance Cost, Monitoring, Recordkeeping and Reporting, Annual Basis	Total Costs, Annual Basis
2016	$0	$0	$0
2017	$0	$0	$0
2018	$0	$0	$0
2019	$3,302,000	$3,092,000	$6,394,000
2020	$3,362,000	$3,148,000	$6,510,000
2021	$3,422,000	$3,204,000	$6,626,000
2022	$3,484,000	$3,262,000	$6,746,000
2023	$3,547,000	$3,321,000	$6,868,000
2024	$3,611,000	$3,381,000	$6,992,000
2025	$3,676,000	$3,441,000	$7,117,000
2026	$3,742,000	$3,503,000	$7,245,000
2027	$3,809,000	$3,566,000	$7,375,000
2028	$3,878,000	$3,631,000	$7,509,000
2029	$3,947,000	$3,696,000	$7,643,000
2030	$4,018,000	$3,763,000	$7,781,000

As mentioned in section II, these rules would create fuel cost savings due to reduced fuel usage. The estimated benefits assumed that the price of fuel grows at 1.1 percent annually from $3.92 per MMBtu in 2019 to $4.42 in 2030 at the end of the period of analysis related to these cost savings. The Division based the annual growth assumption on the EIA's Annual Energy Outlook 2015 data. These rules also create environmental benefits resulting from increased energy efficiency as measured by heat rate improvements. Table 6 presents the result of the state plan for North Carolina, based on 2015 projected prices, and values.

Table 6. Environmental Benefits of the State Plan by North Carolina

Fuel Savings, Annual Basis (Beginning in 2019)	Total CO_2 Emissions Reductions (tons/year)
-$7,317,000	191,826

Table 7, Estimated Fiscal Impact Summary of the State Plan by North Carolina, presents a summary of the fiscal impacts of the proposed rules, known as the State Plan by North Carolina. It includes the private sector costs and included the cost-savings due to reductions in fuel usage that are a result of heat rate improvements. The value of the net fiscal impacts is -$5,888,000.

Table 7. Estimated Fiscal Impact Summary of the State Plan by North Carolina

Year	Local Government	State Government	Private Sector (Costs)	Private Sector (Savings)	Total Impact (+ for Net Cost, - for Net Savings)
2016	$0	$0	$0	$0	$0
2017	$0	$0	$0	$0	$0
2018	$0	$0	$0	$0	$0
2019	$0	$0	$6,394,000	-$7,317,000	-$923,000
2020	$0	$0	$6,510,000	-$7,397,000	-$887,000
2021	$0	$0	$6,626,000	-$7,479,000	-$853,000
2022	$0	$0	$6,746,000	-$7,561,000	-$815,000
2023	$0	$0	$6,868,000	-$7,644,000	-$776,000
2024	$0	$0	$6,992,000	-$7,728,000	-$736,000
2025	$0	$0	$7,117,000	-$7,813,000	-$696,000
2026	$0	$0	$7,245,000	-$7,899,000	-$654,000
2027	$0	$0	$7,375,000	-$7,986,000	-$611,000
2028	$0	$0	$7,509,000	-$8,074,000	-$565,000
2029	$0	$0	$7,643,000	-$8,163,000	-$520,000
2030	$0	$0	$7,781,000	-$8,252,000	-$471,000
NPV	$0	$0	$55,337,000	-$61,225,000	-$5,888,000

VI. Consideration of Alternatives, uncertainty and sensitivity in the economic analysis

The agency considered the following options while drafting the rules but found them less desirable:

1. *Maintaining status quo*. This option would not have met the agency's obligations under the Clean Air Act Section 111(d). Additionally, the proposed option results in net benefits and reduced CO_2 emissions in comparison to the status quo (baseline scenario).

2. *Requiring the affected units to implement the BSER measures prescribed in the rule without the option of developing alternatives.* The rules as proposed allow sources to develop alternatives to the BSER that provides equal or better control of CO_2 emissions for any unit described in 15A NCAC 02D .2703. The previous option did not recognize factors that could affect that determination and change prior to the compliance deadline of September 1, 2019. Therefore, the proposed rule change may result in higher benefits that are presented in this fiscal and regulatory impact analysis.

3. *Requiring EGUs to implement additional BSER measures.* All of the measures discussed in the BSER evaluation were alternatives for any of the coal-fired electrical generating units; however, only those that were cost-effective remained in the final rule. See the

DAQ supporting documentation for this rulemaking, available on the agency's website, for the calculation of the costs EGUs would have incurred from different BSER measures.[16]

There are a number of uncertainties that may affect the estimate net benefit of $5.89 million in the next 15 years. There may be costs that the plants would incur if they choose to provide an alternative BSER demonstration. It is difficult to know what that exact cost may be, but it would likely be offset by any marginal benefit incurred from the alternative. An affected electrical generating unit could incur some additional costs for the HRI evaluations needed to submit for permitting and the monitoring and recordkeeping requirements. DAQ may also incur some opportunity cost for reviewing the alternative. Allowing such flexibility may reduce the costs estimates of the rules presented in this fiscal and regulatory analysis.

There is uncertainty in this analysis because of the range of costs that could occur. Some singular BSER measures may be different when combined. The consideration of alternative outcomes may depend on the future price of coal, which may affect fuel-savings. Evaluating these factors throughout the process may ensure the goal of requiring cost effective alternatives now and in the future.

The expected change from the regulatory baseline predicted in this economic analysis is unlikely to increase electrical utility rates. At the time of this analysis, DAQ is predicting an overall net cost-savings due to the heat rate improvements that have been discussed. However, the sensitivity of these predictions is highly dependent on uncertainty due to some cost estimates. The affected facilities provided a range for the estimated capital expenditures and annual operation and maintenance costs that in some cases varied between -20 percent to +75 percent of the most likely scenario the facilities identified. That wide range of cost estimates may result in net impacts that differ from those estimated above. Performing a sensitivity analysis around the capital and operation and maintenance costs is complicated by the fact that the most likely cost estimate, as indicated by the regulated community, is for some BSER measures at the lower end of the range, while for others at the high end or anywhere in between. If the marginal costs ultimately are much higher than predicted and outweigh the fuel savings, then the size of that change has the potential to cause the electrical generators to pass along those costs to the consumers of electricity. It is impossible to predict how those factors could effect that decision in advance. A mechanism exists to make a rate case before the North Carolina Utility Commission if that becomes necessary in the future.

This analysis also assumed that the annualized capital expenditures and the annual costs for operation, maintenance, monitoring, reporting, and recordkeeping would increase at a rate of 1.8 percent per year. Also, in estimating potential future fuel savings as a result of the proposed rules, DAQ used a projected delivery cost of coal price of $3.92 per million Btu in 2019 and then assumed a 1.1 percent annual growth until 2030. There are inherent uncertainties related to using a forecast that goes far into the future, and the fuel cost savings estimated may be impacted by

[16] Supporting Basis for Determination of Best System of Emissions Reduction for Carbon Dioxide (CO2) Emissions from Existing Electric Utility Generating Units
http://daq.state.nc.us/Calendar/Planning/November2015AQC/Agenda_3.2.pdf

unforeseen changes in the coal or natural gas markets. Additionally, the net benefit estimate of $5.89 million through 2030 (see NPV value in Table 7) may be smaller if the analysis used the estimate of $3.64 per million Btu coal delivery prince in 2019 based on the Duke Energy Progress cost information (see in Appendix 2). Table 8 below shows how the estimated net benefit of $5.89 million from the proposed rules would differ if these assumptions were to vary.

Table 8. Sensitivity Analysis around Annual Cost Growth Assumptions

Impact (+ for Net Cost, - for Net Savings)		Assumption on Annual Growth Rate of Capital, O&M, and MR&R Costs					
		1.75%	**1.80%**	2%	2.50%	3%	3.50%
Assumption on	0.75%	-$5.03	-$4.89	-$4.35	-$2.98	-$1.56	-$0.11
Annual Growth	1.00%	-$5.74	-$5.60	-$5.06	-$3.69	-$2.27	-$0.82
Rate of Delivery	**1.10%**	-$6.03	**-$5.89**	-$5.35	-$3.98	-$2.56	-$1.11
Price of Coal	1.25%	-$6.47	-$6.33	-$5.79	-$4.43	-$3.00	-$1.55

Additionally, given that some of the BSER measures required by the rules have clear net benefits, the facilities may decide to implement them regardless of whether the proposed rules are enacted or not. If such a case were to be true, then these measures would not be an impact from these rules, but rather part of the baseline for this analysis, potentially causing the impacts of the rules to change. The Division does not have the necessary information to determine which measures for each EGU affected would be part of the baseline scenario.

There is a lot of uncertainty related to the legal aspects of a federal plan that might come into play if the EPA finds the NC state plan to be inadequate, and therefore it is difficult to discuss the outcome of that possibility. A narrow perspective that only focuses on the building block 1 that allows for emission trading seems to lead to conclusions that such an alternative offers a more cost-effective solution than a state plan that does not allow emission trading. Measuring the fiscal impacts compared with some federal alternative would likely lead to a conclusion that the proposed state plan is less costly compared to a future without a federal plan. There are even more uncertainties in estimated economic impacts around that prediction, and the chosen approach avoided those problems.

Also, the legal uncertainties surrounding the federal guidelines contained in 40 CFR 60 Subpart UUUU may further affect the estimates discussed above. The proposed rules include text that would render all or part of the requirements in the rules invalid if legal proceedings find against the federal emission guidelines. In such a case, the requirements that would be invalidated would cause the estimated costs and benefits in this analysis to decrease or not occur at all.

There is inherently a need for consideration of maintaining reliability in the electrical power grid sector when developing state plans, and allowing a safety value triggered when there is conflict between requirements of a state plan and maintenance of reliable electrical power.

VII. Conclusions

Federal law requires the proposed rules, however North Carolina has the option to adopt a state plan that uses a case-by-case approach, which considers cost-effective measures to reduce CO_2 emissions as well as the useful remaining life of any facility. These proposed rules are expected to become effective by September 1, 2016, and the compliance date is September 1, 2019. This analysis identified private sector measures for work practice standards that require the expenditure of capital, as well as annual operation and maintenance expenses. It also identifies benefits from using less coal with cost-savings due to heat rate improvements. No impacts on either the State of North Carolina nor any units of local governments occurred during the period of analysis of the proposed rules.

Beginning in 2019, the annual net positive impacts to the private sector are estimated from change from $923,000 to $471,000 by 2030. The estimated annual costs and benefits of these proposed rules is substantial as defined in North Carolina's Administrative Procedures Act in NC General Statute 150B-21.4, Fiscal and Regulatory Impact Analysis on Rules. The term "substantial economic impact" means an aggregate financial impact on all persons affected of at least one million dollars ($1,000,000) in a 12-month period.

15A NCAC 02D .2701 is proposed for adoption as follows:

SECTION .2700 – STANDARDS OF PERFORMANCE FOR EXISTING ELECTRIC UTILITY GENERATING UNITS UNDER CLEAN AIR ACT SECTION 111(d)

15A NCAC 02D .2701 PURPOSE AND APPLICABILITY

(a) Purpose. The purpose of this Section is to implement the provision(s) in Clean Air Act Section 111(d) for Best System of Emission Reduction for Existing Electric Generating Units to reduce the emissions of carbon dioxide through heat rate improvement.

(b) Applicability. This Section applies to the following,that are fossil fuel-fired steam electric utility generating units (EGUs) to the extent they are subject to regulation in 40 CFR Part 60.5845 that:

(1) Serve a generator connected to a utility power distribution system with a nameplate capacity of 25 MW-net or greater and capable of selling greater than 25 MW of electricity;

(2) Have a base load rating or design heat input capacity greater than 250 MMBtu/hr or greater heat input of fossil fuel either alone or in combination with any other fuel; and

(3) Are stationary combustion turbines that meet the definition of either a natural gas combined cycle or combined heat and power combustion turbine.

(c) Excluded units. This Section does not apply to the fossil fuel-fired steam EGUs that are excluded under 40 CFR Part 60.5850.

(d) Retired unit exemption. Any unit that is permanently retired shall be exempted from this Section as of its retirement date.

(e) Effect on other authorities. No provision of this Section, any application submitted or any permit issued pursuant to 15A NCAC 02D .2704 of this Section shall be construed as exempting any unit or source covered under this Section or the owner or operator from complying with any other requirements of this Subchapter or Subchapter 15A NCAC 02Q.

(f) In the event all or any portion of 40 CFR 60 Subpart UUUU containing the guidelines is:

(1) Declared or adjudged to be invalid or unconstitutional or stayed by the United States Court of Appeals for the Fourth Circuit, by the District of Columbia Circuit, or by the United States Supreme Court: or

(2) Withdrawn, repealed, revoked or otherwise rendered of no force and effect by the United States Environmental Protection Agency, Congress, or Presidential Executive Order.

Such action shall render the regulation as incorporated herein, or that portion thereof that may be affected by such action, as invalid, void, stayed, or otherwise without force and effect for purposes of this rule upon the date such action becomes final and effective; provided, further, that such declaration, adjudication, stay, or other action described herein shall not affect the remaining portions, if any, of the regulation as incorporated herein, which shall remain of full force and effect as if such portion so declared or adjudged invalid or unconstitutional or stayed or otherwise invalidated or effected were not originally a part of this rule. The Environmental Management Commission declares that it would not have incorporated the remaining parts of the federal regulation if it had known that such portion thereof would be declared or adjudged invalid or unconstitutional or stayed or otherwise rendered of no force and effect.

History Note: Authority G.S. 143-215.3(a); 143-215.107(a)(5), (10);
Amended Eff. September 1, 2016.

15A NCAC 02D .2702 is proposed for adoption as follows:

15A NCAC 02D .2702 DEFINITIONS

For the purpose of this Section, the following definitions apply.

(1) "Affected electric generating unit (EGU)" means a fossil fuel fired steam generating unit that:
- (A) serves a generator connected to a utility power distribution system with a nameplate capacity of 25 MW-net or greater and capable of selling greater than 25 MW of electricity;
- (B) has a base load rating or design heat input capacity greater than 250 MMBtu/hr or greater heat input of fossil fuel either alone or in combination with any other fuel;
- (C) is a stationary combustion turbine that meets the definition of either a natural gas combined cycle or combined heat and power combustion turbine; and
- (D) includes, and shall not extend beyond, the following systems: fuel combustion system, combustion air system, steam system, draft system, turbine system, air pollution control system, cooling system, and auxiliary equipment contained within the facility that uses electrical power.

(2) “Air heater leakage reduction (ALR)” means to reduce air leakage between the combustion air and the exhaust gas of Lungstrom, or rotary air heaters by removal of existing air preheater seals and replacing them with newer high performance seals.

(3) “Best system of emission reduction (BSER)” means a design, equipment, work practice, or operational standard, or combination thereof, which reflects the best technological system of continuous emission reduction taking into consideration the cost of achieving such reduction, and any non-air quality health and environmental impact and energy requirements.

(4) “Combustion optimization with neural network (CO)” means a system that conducts real-time monitoring and controls fuel and air flow distribution, furnace exhaust gas temperatures, and boiler steam temperatures to maximize heat recovery and minimize carbon monoxide emissions and nitrogen oxides emissions. CO systems are based on nonlinear, multivariable steady-state models derived from historical unit operating data that identify the best combination of

independent operating variables that produce optimum combustion and thermal efficiency with low emissions.

(5) "Condenser rebundle, retube, rebuild (CRR)" means to replace, repair or reconfigure tube elements, tube sheets, the condenser shell and other condenser components in order to correct leaks, plugging and debris build up to increase effective heat transfer surface area, or to otherwise improve heat transfer and fluid flow in the condenser. CRR results in greater and more consistent condenser vacuum under the range of boiler operating conditions and available cooling water temperatures.

(6) "Controllable loss reduction (CLR)" means developing and implementing a site-specific plan for best operations and maintenance practices (O&M) to maintain performance. CLR involves a comprehensive effort to collect information that may not be readily collected through existing sensors and data collection systems, interpret all data collected, and make decisions regarding actions to be taken to improve or maintain performance. CLR consists of implementing a plan and instructing staff in the value and practice of collecting and reporting information regarding the ongoing performance of all the pieces of equipment comprising the power plant and implementing changes to operating or maintenance practices that are determined to improve heat rate.

(7) "Forced draft fan variable frequency drive (FDF)" means equipment used to reduce fan power consumption by electronically controlling combustion air flowrate. FDF utilizes a silicon controlled rectifier or equivalent device to control electrical frequency and voltage to the fan motor, thereby matching fan speed and combustion air flowrate with operating load.

(8) "Heat input" from fuel is determined by multiplying the higher heating value of the fuel times the amount of fuel consumed over that time.

(9) "Heat rate" means the amount of fuel thermal energy or heat input in million Btu (MMBtu) used by an electrical generator or power plant to generate one kilowatt-hour (kWh) of electricity. For this rule, heat input is expressed in units of Btu heat input per net kWh generated.

(10) "Induced draft fan or booster fan variable frequency drive (IBD)" means equipment used to reduce fan power consumption by electronically controlling exhaust gas flowrate. IBD utilizes a silicon controlled rectifier or an equivalent device to control electrical frequency and voltage to the fan motor, thereby matching fan speed and exhaust gas flowrate with operating load.

(11) "Intelligent soot blowing (ISB)" means the use of software, instrumentation, sensors, and automated controls to achieve more effective cleaning of furnace wall and convective section heat transfer surfaces. The ISB system may consist of devices for monitoring furnace exhaust gas temperatures, steam temperatures, and furnace wall temperatures at different locations, a control system, and furnace cleaning devices. The ISB's control system digitally processes the received information to evaluate the effects of real-time heat transfer performance in order to allocate high pressure steam or high pressure air to cleaning devices in specified heat transfer zones. The ISB activates furnace cleaning devices (also known as "soot blowers") when measurement sensors

indicate the need to remove ash or slag deposits from the furnace location where it is most effective to do so, resulting in improved boiler efficiency as well as reduced energy demand from soot blower and furnace cleaning systems.

(12) "Nameplate capacity" means nameplate capacity as defined in 40 CFR 60.5880.

(13) "Natural gas" means natural gas as defined in 40 CFR 60.5880.

(14) "Natural gas combined cycle (NGCC)" means an electric generating unit that uses a stationary combustion turbine firing natural gas from which the heat from the combustion turbine exhaust gas is recovered by a heat recovery steam generating unit to generate additional electricity.

(15) "Net generation" means net-electric output as defined in 40 CFR 60.5880.

(16) "Steam generating unit" means any furnace, boiler or other device used for combusting fossil fuel and producing steam plus any integrated equipment that provides electricity or useful thermal energy output to the affected unit or auxiliary equipment.

(17) "Variable speed drives" means a system to increase and decrease the operating speed of fluid moving equipment such as fans or pumps by reducing the drives' rotational speed in revolutions per minute to meet required changes in fluid flow rates.

History Note: Authority G.S. 143-215.3(a); 143-215.107(a)(5), (10);
Amended Eff. September 1, 2016.

15A NCAC 02D .2703 is proposed for adoption as follows:

15A NCAC 02D .2703 STANDARDS OF PERFORMANCE REQUIREMENTS FOR CARBON DIOXIDE

(a) This Section applies to affected electric generating units (EGUs) listed below. The owner or operator shall apply the following heat rate improvement measures, identified as Best System of Emission Reduction (BSER) measures for carbon dioxide emissions at the affected EGU or an alternative BSER approved pursuant to Paragraph (e) of this Rule at the affected EGU.

Affected Units - Coal-fired EGUs		
Utility Company - Facility	**Unit ID**	**Best System of Emission Reduction Measure(s)**
Duke Energy - Asheville	1	none
Duke Energy - Asheville	2	none
Duke Energy - Belews Creek	1	CLR and FDF
Duke Energy - Belews Creek	2	CLR and FDF
Duke Energy - Cliffside	5	none
Duke Energy - Cliffside	6	ALR, CO, FDF, and ISB
Duke Energy - G G Allen	1	none

Duke Energy - G G Allen	2	none
Duke Energy - G G Allen	3	none
Duke Energy - G G Allen	4	none
Duke Energy - G G Allen	5	none
Duke Energy - Marshall	1	ISB
Duke Energy - Marshall	2	ISB
Duke Energy - Marshall	3	ALR, CO, FDF and ISB
Duke Energy - Marshall	4	ALR, CO, FDF and ISB
Duke Energy - Mayo	1A & 1B	none
Duke Energy - Roxboro	1	none
Duke Energy - Roxboro	2	FDF, IBD and ISB
Duke Energy - Roxboro	3A & 3B	ISB
Duke Energy - Roxboro	4A & 4B	ISB
Edgecombe Genco - Battleboro	1	none
Edgecombe Genco - Battleboro	2	none
Westmoreland Partners - Roanoke Valley Energy Facility I	1	none
Westmoreland Partners - Roanoke Valley Energy Facility II	1	none

Affected Units -Natural Gas Combined Cycle EGUs

Utility Company - Facility	**Unit ID**	**Best System of Emission Reduction Measure(s)**
Dominion Resources - Rosemary	GEN1	NGCC operation firing natural gas
Dominion Resources - Rosemary	GEN2	
Dominion Resources - Rosemary	GEN3	
Duke Energy - Buck	CT11	
Duke Energy - Buck	CT12	
Duke Energy - Buck	ST10	
Duke Energy - Dan River	CT8	
Duke Energy - Dan River	CT9	
Duke Energy - Dan River	ST7	
Duke Energy - H F Lee	1A	
Duke Energy - H F Lee	1B	
Duke Energy - H F Lee	1C	
Duke Energy - H F Lee	ST1	

Duke Energy - L V Sutton	1A	
Duke Energy - L V Sutton	1B	
Duke Energy - L V Sutton	ST1	
Duke Energy - Sherwood H Smith Jr	7	
Duke Energy - Sherwood H Smith Jr	8	
Duke Energy - Sherwood H Smith Jr	9	
Duke Energy - Sherwood H Smith Jr	10	
Duke Energy - Sherwood H Smith Jr	ST4	
Duke Energy - Sherwood H Smith Jr	ST5	
Public Works Commission – Butler Warner	1	
Public Works Commission – Butler Warner	2	
Public Works Commission – Butler Warner	3	
Public Works Commission – Butler Warner	6	
Public Works Commission – Butler Warner	7	
Public Works Commission – Butler Warner	8	
Public Works Commission – Butler Warner	9	
Southern Company - Rowan	4	
Southern Company - Rowan	5	
Southern Company - Rowan	STG	

(b) The following work practice standards shall be applied for each BSER measure identified for the affected EGUs:

(1) Air heater leakage reduction (ALR), Forced draft fan variable frequency drive (FDF), Induced draft fan and/or booster fan variable frequency drive (IBD), and Condenser rebundle, retube, rebuild (CRR).

(A) Installation shall be performed according to each manufacturer's installation procedures. The owner or operator shall follow each manufacturer's performance acceptance test procedures, assure the performance test acceptance criteria are met, and document the acceptance test results.

(B) Ongoing maintenance shall be performed according to each manufacturer's recommended maintenance procedures at the prescribed frequency levels.

(2) Intelligent soot blowing (ISB) and Combustion Optimization and Neural Networks (CO).

(A) Installation shall be performed in accordance with each manufacturer's specification and site-specific design. The owner or operator shall verify performance of each BSER measure in accordance with each manufacturer's performance acceptance test procedures, assure the performance acceptance test criteria are met, and document the acceptance test results.

(B) Plant personnel responsible for the operation of each BSER measure shall follow procedures to best utilize the measure per each manufacturer's operating guidelines and to best achieve the goal of reducing heat rate.

(C) Ongoing maintenance shall be performed according to each manufacturer's recommended maintenance procedures at the prescribed frequency levels.

(3) Controllable loss reduction (CLR).

(A) The owner or operator shall develop an EGU-specific CLR plan and submit an electronic copy of the plan to the Director of the Division of Air Quality within one year of the initial effective date of this rule. This plan shall include the devices and methods for measuring performance parameters; requirements for the frequency of data collection; method(s) for collecting and reporting the data; procedures for identifying a loss in EGU efficiency including any calculations; actions identified to improve EGU heat rate including equipment optimization or maintenance or changes to EGU operating methods; and a schedule for implementation of the actions to be taken.

(B) The owner or operator shall implement actions identified by the CLR plan within the timeframe specified by the plan. The owner or operator shall maintain all sensors, instrumentation, information technology, or other equipment used by the CLR plan in accordance with the equipment manufacturers' maintenance procedures and schedule.

(4) Natural gas combined cycle operation (NGCC).

(A) The owner or operator shall operate the NGCC unit, including the combustion turbine and the associated heat recovery steam generator, using natural gas as fuel during normal operation in accordance with the manufacturers' recommended procedures.

(B) Ongoing maintenance shall be performed according to the manufacturer's recommended maintenance procedures at the prescribed frequency levels.

(c) Alternative BSER. The owner or operator of an affected unit may apply one or more alternative measures that constitute the best system of emissions reduction for carbon dioxide emissions from coal-fired EGUs on a unit-specific basis upon approval by the Director by demonstrating to the Director that application of the alternative measures on a unit-specific basis would achieve an equivalent or greater heat rate improvement than application of the measures identified in Paragraph (a) of this Rule.

(d) Any alternative BSER demonstration shall be submitted no later than six months after the initial effective date of this Rule and shall include:

(1) the name and address of the company and the name and telephone number of a company officer over whose signature the demonstration is submitted;

(2) a description of all operations conducted at the location to which the demonstration applies and the purpose that the equipment serves within the operations;

(3) the type of EGU;

(4) the remaining useful life of the EGU ;

(5) the unit's calendar year 2015 baseline data including net heat rate, net generation, annual capacity factor, and carbon dioxide emissions;

(6) the unit's projected 2019 capacity factor based on heat input and net generation;

(7) reference to the specific operational and equipment controls or measures in the Tables in Paragraph (a) of this Rule for which alternative operational or equipment controls or measures are proposed;

(8) a description of the proposed alternative operational or equipment controls or measures, the magnitude of carbon dioxide emission reduction that will be achieved, and the quantity of carbon dioxide that will be emitted if the alternative operational or equipment controls or measures are instituted;

(9) whether the proposed measure is adequately demonstrated pursuant to Clean Air Act Section 111(a)(1) to reduce heat rate;

(10) the feasibility of applying a specific heat rate improvement measure on a given unit;

(11) the degree of heat rate reduction potential for a specific feasible heat rate improvement measure;

(12) a description of any site-specific limitations;

(13) the associated costs of the proposed alternative equipment or measure including capital, fixed and variable operational and maintenance (O&M) costs and fuel savings;

(14) the cost per ton of carbon dioxide emissions reduction;

(15) any non-air quality health and environmental impact and energy requirements;

(16) a schedule for the installation or institution of the alternative operational or equipment controls or measures to achieve compliance by the date specified in Paragraph (g) of this Rule including increments of progress specified in 40 CFR 60.21(h); and

(17) certification in the form of a written statement signed by the responsible official as defined in 15A NCAC 02Q .0502 that emissions of all other air contaminants from the subject source are in compliance with all applicable local, state and federal laws and regulations.

(18) the company's basis of the alternative control capability to achieve equivalent or greater carbon dioxide emission reductions than the measure included in Paragraph (a) of this Rule.

The demonstration may include a copy of the permit application and need not duplicate information in the permit application.

(e) The Director shall approve a demonstration for alternative control if:

(1) The demonstration is submitted in accordance with Paragraph (d) of this Rule;

(2) All other air contaminant emissions from the facility are in compliance with, or under a schedule for compliance with, all applicable local, state, and federal regulations;

(3) Based on the Division's technical analysis of the unit-specific information provided under Paragraph (d) of this Rule, the Director determines that application of the alternative measures on a unit-specific basis would achieve an equivalent or greater heat rate improvement than application of the measures identified in Paragraph (a) of this Rule; and

(4) The demonstration contains a schedule, including increments of progress specified in 40 CFR 60.21(h), for the installation or institution of the alternative operational or equipment controls or measures to achieve the heat rate improvement by the compliance date specified in Paragraph (g) of this Rule.

(f) When measures different from those specified in the Tables in Paragraph (a) of this Rule are approved by the Director, the permit shall contain a condition stating such controls and associated monitoring, recordkeeping, and reporting requirements to verify implementation of the measures.

(g) Compliance schedule. Owners and operators of the affected facilities in Paragraph (b) of this Rule shall implement the identified BSER measures or alternative BSER approved pursuant to Paragraph (e) of this Rule by September 1, 2019 that were not in place prior to the following date for the corresponding affected utility company(s):

(1) July 31, 2015 for all affected EGUs for Duke Energy,

(2) August 31, 2015 for all affected EGUs for both Edgecombe Genco - Battleboro and Westmoreland Partners - Roanoke Valley Energy Facility.

(h) All alternative BSER demonstrations, and any modifications or changes to those determinations, approved or determined by the Division pursuant to Paragraphs (c) through (e) of this Rule shall be submitted by the Division to the U.S. Environmental Protection Agency (EPA) as a revision to the state plan. No alternative BSER demonstration, nor any modification or change to a demonstration, approved or determined by the Division pursuant to Paragraphs (c) through (e) of this Rule shall revise the state plan or be used as a state plan credit, until it is approved by the U.S. EPA as a state plan revision.

History Note: Authority G.S. 143-215.3(a); 143-215.65; 143-215.66; 143-215.107(a)(5), (10);
Amended Eff. September 1, 2016.

15A NCAC 02D .2704 is proposed for adoption as follows:

15A NCAC 02D .2704 PERMITTING

(a) The owner or operator of any source covered under this Section shall submit permit applications as required containing heat rate improvement evaluations for each affected unit to comply with the requirements of this Section following the procedures and requirements in 15A NCAC 02Q .0500 containing Title V permitting procedures for each affected source. The owner or operator may determine that an alternative BSER measure would achieve an equivalent or greater heat rate reduction than achieved under the requirements of the BSER measures identified in 15A NCAC 02D .2703(a). In such a situation the owner or operator shall follow the procedures contained in 15A NCAC 02D .2703(c) and (d).

(b) The Director shall review applications submitted under Paragraph (a) of this Rule and issue permits for compliance with this Section following the procedures and requirements in 15A NCAC 02Q .0500 (Title V permitting procedures) for each affected source. In the event that the owner or operator submits a permit application with an alternative BSER following the procedures contained in 15A NCAC 02D .2703(c) and (d), the Director shall review applications submitted under Paragraph (a) of this Rule and issue permits for compliance with this Section following the procedures and requirements contained in 15A NCAC 02D .2703(e).

History Note: Authority G.S. 143-215.3(a); 143-215.107(a)(5), (10); 143-215.108;
Amended Eff. September 1, 2016.

15A NCAC 02D .2705 is proposed for adoption as follows:

15A NCAC 02D .2705 MONITORING, RECORDKEEPING AND REPORTING

(a) For measures implemented under 15A NCAC 02D .2703(a), the following monitoring, recordkeeping and reporting activities shall be performed for each air heater leakage reduction (ALR), forced draft fan variable frequency drive (FVD), induced draft fan or booster fan variable frequency drive (IBD) and condenser rebundle, retube, rebuild (CRR):

(1) The owner or operator shall record installation activities completed, including the corresponding dates of completion, maintain the installation records on site, and the records shall be available for review by the Division of Air Quality. Installation records refers to work orders, invoices, permits, photographs, engineering drawings or specifications and other documentation routinely developed to install or modify equipment or otherwise make plant improvements.

(2) The owner or operator shall record maintenance activities completed, including the corresponding dates, maintain the records on site for ten years, and the records shall be available for review by the Division of Air Quality.

(b) For measures implemented under 15A NCAC 02D .2703(a), the following monitoring, recordkeeping and reporting activities shall be performed for each intelligent soot blowing (ISB) and combustion optimization with neural network (CO):

(1) The owner or operator shall record installation activities completed, including the corresponding dates of completion, maintain the installation records on site for ten years, and the records shall be available for review by the Division of Air Quality. Installation records refers to work orders, invoices, permits, photographs, engineering drawings or specifications and other documentation routinely developed to install or modify equipment or otherwise make plant improvements.

(2) The owner or operator shall monitor and record all operating parameters associated with each BSER measure required in 15A NCAC 02D .2703(a) and their respective control systems in accordance with the manufacturer's recommended operating procedures. The owner or operator shall record forced or operational outages of the BSER measures, the corresponding time period and the reason(s) why. The owner or operator shall maintain the operating records on site for ten years and the operating records shall be available for review by the Division of Air Quality.

(3) The owner or operator shall record maintenance activities completed, including the corresponding dates, maintain the records on site for ten years, and the records shall be available for review by the Division of Air Quality.

(c) The following monitoring, recordkeeping and reporting activities shall be performed for controllable loss reduction (CLR):

(1) The owner or operator shall submit an electronic copy of the CLR plan to the Director of the Division of Air Quality within one year of the initial effective date of this rule.

(2) The owner or operator shall monitor and record all parameters defined in the CLR plan in accordance to the procedures defined in the plan. The owner operator shall maintain electronic records of the data collected and any calculations associated with the CLR plan and the records shall be available for review by the Division of Air Quality.

(3) The owner or operator shall record instances where the CLR plan identified a loss in EGU heat rate and any actions taken or the rationale and related information as to why action was not taken.

(d) The following monitoring, recordkeeping and reporting activities shall be performed for natural gas combined cycle (NGCC):

(1) The owner or operator shall monitor and record all operating parameters associated with NGCC and its respective control systems in accordance with the manufacturer's recommended operating procedures. The owner or operator shall maintain the operating records on site for ten years and the operating records shall be available for review by the Division of Air Quality.

(2) The owner or operator shall record maintenance activities completed, including the corresponding dates, maintain the records on site for ten years, and the records shall be available for review by the Division of Air Quality.

(e) In the event that the owner or operator submits a permit application with an alternative BSER following the procedures contained in 15A NCAC 02D .2703(c) and (d), then the owner or operator shall submit a permit application that includes monitoring, recordkeeping and reporting activities for the installation, operation and maintenance of the alternative BSER measure in accordance with the manufacturer's recommended procedures.

(f) The owner or operator shall submit an annual compliance report to the Director of the Division of Air Quality each year starting one year from the initial effective date of this Rule. The annual compliance report shall include:

(1) The following parameters on an annual average basis:

(A) Carbon dioxide emissions in short tons;

(B) Net electrical generation in MWh-net;

(C) Heat input in MMBtu;

(D) Gross electrical generation in MWh-gross;

(E) Calculated heat rate in Btu/kWh-net; and

(F) Calculated carbon dioxide emission rate in lb/MWh-net.

(2) Activities resulting from compliance with this Rule and the corresponding date(s) including:

(A) Installation of equipment related to the BSER measures;

(B) Forced or operational outages of equipment lasting longer than ten days related to the BSER measures, the corresponding time period and the reason(s) why;

(C) Instances where operational procedures associated with the BSER measures were not observed for an period lasting longer than ten days and the reason(s) why; and

(D) Instances where a loss in EGU heat rate was identified in the CLR plan and the resulting actions taken or, the rationale and related information as to why no action was taken.

History Note: Authority G.S. 143-215.3(a); 143-215.65; 143-215.66; 143-215.107(a)(5), (10);
Amended Eff. September 1, 2016.

Appendix 2
Estimation of Coal Delivery Price

The US Energy Information Administration estimated/ projected nationwide coal delivered prices to be:

- 2013: $2.50 per million Btu
- 2015: $2.41 per million Btu
- 2020: $2.54 per million Btu

By interpolation, DAQ computed the nationwide coal delivered prices for 2014 and 2019 to be approximately $2.46 per million Btu and $2.51 per million, respectively; thus an increase of 2 percent of coal price was projected from 2014 to 2019. Applying this percentage to the Duke Energy Carolina's fleet, the average coal delivered price in 2019 would be 1.02 * $3.84 per million Btu = $3.92 per million Btu. Applying the same ratio to the Duke Energy Progress fleet, the average coal delivered price in 2019 would be 1.02 * $3.57 per million Btu = $3.64 per million Btu.

Since only three of the 10 affected units are part of the Duke Energy Progress fleet, DAQ is using the larger value of **$3.92 per million Btu** from the above for the coal delivery cost in 2019, for the entire NC fleet of affected coal-fueled units.